Petroleum news

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This week's Mining News

NORTH OF 60 MINING news

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NEWS NUGGETS

Compiled by Shane Lasley

Willow Creek Mine on fast track

Miranda Gold Corp. March 3 said Gold Torrent plans to fast-track the Coleman gold deposit at the Willow Creek property into production in 24-30 months. Initial production estimates are for 21,000 ounces of gold annually from the mining and milling of 150 tons per day at the Southcentral Alaska project. Gold Torrent, which anticipates that gravity methods can achieve greater than 80 percent gold recovery, believes that the lack of chemicals should expedite permitting. A new resource estimate for the Coleman deposit is anticipated within two months. Miranda said a feasibility study scheduled for completion by mid-year will provide shareholders of both companies with insight into the financial parameters of mining Coleman. In addition to activities associated with mine planning and permitting, Gold Torrent will investigate the possible rehabilitation of the Enserch tunnel to access the Lucky Shot vein system for production and drilling. According to an agreement with Miranda, Gold Torrent will fund US$10 million of expenditures to incrementally earn a 70 percent joint venture interest in Willow Creek.

Dowa OKs US$5 million for Palmer

Constantine Metal Resources Ltd. March 3 said that Dowa Metals & Mining Co., Ltd. has approved a 2015 budget of US$5 million for the continued exploration of the Palmer project in Southeast Alaska. Dowa, which has the option to earn 49 percent in Palmer by investing US$22 million, had spent roughly US$10 million at the project through the end of 2014. This year's drilling will focus on extending volcanogenic massive sulfide mineralization encountered at the South Wall zone in 2014, including the 89 meters of 0.8 percent copper and 5.0 percent zinc intersected in hole CMR14-65.

Booth fills executive void at Redstar

Redstar Gold Corp. Feb. 25 reported that Ken Booth has resumed the role of interim president and CEO, replacing Toby Mayo who is leaving the company. Booth began his career as a geologist and later embarked on a career in banking and investment banking. He has served as the CEO of several public companies and is currently a director of two exploration companies. Booth is a director of Redstar and served as interim CEO of the company from March to September 2014.

RARE EARTHS

Refining rare earths

Ucore pioneers new method of separating REEs into high purity salts

By SHANE LASLEY

Mining News

Ucore Rare Metals Inc. has reached another milestone in its quest to separate rare earths into the individual elements needed in high-tech devices.

In testing molecular recognition technology, a proprietary method of separating rare earths developed by Utah-based IBC Advanced Technologies, the rare earths found at Ucore's Bokan Mountain project in Southeast Alaska have been segregated as individual salts exceeding 99 percent purity.

"MRT offers a means of separating REEs to high purity in a rapid and cost effective manner, and with an exceptional level of selectivity and precision," said Ucore President and CEO Jim McKenzie.

JIM MCKENZIE

The avant-garde technology could turn the company into a front-runner in economic and environmentally sound rare earth separation worldwide.

"It's very gratifying to see the fruition of this work and achieve such a high level of success. It is exciting to think of the business opportunities this can create for Ucore and for Alaska," said Ucore COO Ken Collison.

Sen. Orrin Hatch, R-Utah, says opportunities offered by MRT could touch numerous industrial sectors across the United States.

"This breakthrough represents advanced American technology being used to address a uniquely American challenge. Securing the most critical specialty metals is essential to fuel our nation's technology engines," said Hatch. "Rare earths such as dysprosium, terbium, and neodymium are increasingly important to U.S. military, transportation, medical, and super-computing applications as we compete across the globe."

"In my opinion, Ucore now has the opportunity to both extract and purify heavy REEs completely within the U.S. This is a remarkable win for American technology independence from China." —Jack Lifton, principal co-founder, Technology Metals Research

Three-step process

The MRT process is designed to bind selectively with ions based on multiple parameters such as size, chemistry, and geometry. Conventional technologies such as ion exchange, solvent extraction and precipitation generally recognize differences between ions based only on a single parameter.

MRT can separate tightly interlocked rare earths into individual salts in three steps, an achievement that took up to dozens of phases using forerunner technologies.

The basic idea behind the MRT process is that certain resins, known as SuperLig® resins, grab ions based on a number of traits. The technology has already been proven in mining, especially for applications in platinum group metal recovery and removing bismuth impurities from copper.

In creating a REE separation process for Ucore, IBC created resins specifically to bind to the parameters of ions associated with rare earths.

Using a pregnant leach solution prepared from material taken from the Dotson Ridge deposit at Bokan, IBC developed a three-step process for creating nearly pure rare earths.

In the first step, scandium and cerium were extracted. The remaining rare earth elements were then separated into two groups roughly defined as

see RARE EARTHS page 14

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Ucore Rare Metals continues its quest to separate rare earths into the individual elements needed in high-tech devices. Page 11.

Walker v. House Republicans: battle of gas line wills escalates

The battle of philosophical gas line development wills between Alaska Gov. Bill Walker and leading House members continues to escalate.

GOV. BILL WALKER

The two sides have been sparring ever since Walker announced his intent to expand the scope of the in-state line two weeks ago.

This puzzled some House members, including Speaker Mike Chenault and Rep. Mike Hawker, architects of the in-state line known as ASAP.

They now believe Walker has created unnecessary compe-

see GAS LINE BATTLE page 23

Repsol gaining confidence on plan

Repsol YPF will decide whether to pursue a development in Alaska early next year.

The Spanish supermajor intends to make a decision about its proposed North Slope development after completing a three-well appraisal program currently under way, Chief Executive Officer Josu Jon Imaz told analysts during a March 2 earnings call.

Although warning that the company would need to wait to see the results of the current exploration program before it could make a decision, Imaz said there was a "a high probability" of drafting a development plan and making a decision in early 2016.

In early 2013, after completing its second drilling season in Alaska, the company announced three discoveries in the region between the Kuparuk River and Colville River units. The com-

see REPSOL PLAN page 18

EXPLORATION & PRODUCTION

Mustang under way

Alaska company drilled initial injection well in January, planning two more

By ERIC LIDJI

For Petroleum News

The Mustang development is under way. Brooks Range Petroleum Corp. began drilling its first development well at the North Slope field in early January using Nabors rig 16E. The approximately 9,300-foot SMU-M02 well is a directional injection well to support Southern Miluveach unit production.

The well is the first in a three-well development program planned for this winter. The next two, SMU-M03 and SMU-M04, will be horizontal production wells. The Alaska Oil and Gas Conservation Commission issued a drilling permit for SMU-M03 on Feb. 13.

The Mustang field is the initial development project at Southern Miluveach, which sits along the southwestern border of the Kuparuk River unit, north of the Tarn satellite.

The Mustang field is the initial development project at Southern Miluveach, which sits along the southwestern border of the Kuparuk River unit, north of the Tarn satellite.

The program is aimed at bringing the field into production by April 2016. In a plan of development submitted to the Alaska Division of Oil and

see MUSTANG WELL page 18

EXPLORATION & PRODUCTION

Beechey's fate unclear

State termination proceedings began last year; BRPC wants to consolidate prospects

By ERIC LIDJI

For Petroleum News

The state is considering the fate of the Beechey Point unit.

The Alaska Department of Natural Resources started termination proceedings for the North Slope unit last September, although it agreed to reconsider after operator Brooks Range Petroleum Corp. made a case for maintaining the unit in the Gwydyr Bay region.

Then-Commissioner of Natural Resources Joe Balash initiated the termination proceedings in September 2014, saying the Alaska-based company had failed to meet certain work commitments in

"The potential for successful exploration and development in this area requires the compilation of several prospects with known reservoir reserves in close proximity to one another." —Brooks Range Petroleum Vice President for Exploration Larry Vendl

its initial five-year plan of development and failed to meet any of the conditions for justifying an extension. In addition to obvious conditions like sustained oil or gas production or ongoing explo-

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NATURAL GAS

Petronas reawakens

Top-level delegation sent amid signs LNG project emerging from brief hibernation

By GARY PARK

For Petroleum News

Despite the absence of any final corporate sanctioning of projects, British Columbia is coming to life with some renewed hope for an LNG industry.

The Pacific NorthWest joint venture, headed by Petronas, will make a decision by the end of June to go ahead with its plans, providing it can lock up a deal to sell another 10-12 percent equity stake to another Chinese partner.

Three executives from the Malaysian state-owned giant emerged from three months of hibernation to meet with the British Columbia government, prompting Natural Gas Development Minister Rich Coleman to suggest that an approval

Barry Munro, Ernst and Young's Canadian oil and gas leader, said British Columbia, despite the challenges it faces from capital costs, offers world-class, potentially low-cost natural gas supplies.

might be in the offing.

He said the proponents reported progress in lowering the capital costs from prospective contractors and suppliers.

"Evidently, those costs have come down dramatically," Coleman reported to the provincial legislature Feb. 26.

Optimism was bolstered by the make-up of the

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GOVERNMENT

Stedman: Give governor time on gas line

Sitka Republican cites value of Energy Council information for Alaska, confidence in state team working on Alaska LNG project

By STEVE QUINN
For Petroleum News

Sen. Bert Stedman spent the week in Washington, D.C., taking advantage of some good timing. The Sitka Republican serves on the National Petroleum Council, which is drafting a report on Arctic development and research. While there Stedman also spent time with the Energy Council during its annual wintertime meeting in Washington.

At a time when lawmakers are holding down travel spending, Stedman is one of three Senators traveling. Just a few years ago teams of lawmakers traveled.


SEN. BERT STEDMAN

Appointed to the Senate in 2003 by former Gov. Frank Murkowski, Stedman says he has been attending Energy Council meetings for nearly 10 years. He most recently served as chairman.

Before leaving Stedman spoke to Petroleum News about what he believes the value of this trip is and shared thoughts on where the state stands with advancing a natural gas pipeline project.

Q AND A

Petroleum News: Let's start with the National Petroleum Council. What's the value to Alaska on having you as well as Mark Myers on the council, especially with this study?

Stedman: I think it would be a real disservice if there was no Alaskan representation on the subcommittee dealing with this study. Mark Myers was filling the university position and the study was well under way, getting into its final days when he became commissioner of natural resources so rather than make a change, it was preferred that he stay in that position until the report is done.

Quite frankly, he's a lot more knowledgeable than I am in pretty much anything to do to hydrocarbons. He's been very involved in the writing and editing of the report, concentrating on the university side. We've got to remember that the magnitude of the hydrocarbons that are sitting off the coast of Alaska were roughly equal to Russia and we have larger potential than Canada and Norway.

What I expect to come out in this report is that a lot of the technology needed for the Arctic is already proven technology. It needs to be enhanced and updated with some of the work being done off the Russian coast, but the report is going to review current relevant research, technology and the ecology and the human environment.

There is frankly a big disconnect between the average American and the opportunities that Alaska residents have in the Arctic. They are not equal. Some of the communities have virtually no cash economy. Obviously there is no transportation to speak of and connections, plus there is the cost. When we look at opportunities, let's not forget the opportunity of increasing the standard of living for Alaskans living in the area.

One thing that is nice about being on the subcommittee is that you want to have some input from Alaska on any study dealing with the Arctic and hydrocarbons in the Arctic. One of the biggest concerns Alaskans have is we don't have enough participation and our views aren't listened to. You can see it in the timber industry, the oil industry, the fishing industry. Pick your spot.

Petroleum News: So do you present this to the Legislature or someone else perhaps?

Stedman: Mark Myers or myself, we could do it, but I think it would be better if we had someone out of the work group, one of the major authors of the report or someone from the Petroleum Council itself.

Petroleum News: OK, so on to Energy Council, the second part of your trip. What do you hope to accomplish there?

Stedman: What's on people's minds more than the regulatory environment, which is fairly static, is the price and production worldwide of hydrocarbons, particularly oil, and the interplay of natural gas. So we'll be spending some time having presentations on that very subject to bring Energy Council members up to speed on current production and pricing environments. That's pretty high on everybody's agency, but it also ties back to the state and the budgetary process.

For example, the outlook of oil, price wise. We are more price sensitive than volume sensitive and that comes right down to our budget process. In other words if this price reduction is an aberration that's going to be cured the next couple of months and we go back up to $120, that's one thing. But if we stay at $50 or $60 or even $70, that's a whole other ball game we have to deal with. I suspect that's where we're going to be for a little while. Excess supply on the global market, they are talking about a year and a half. That's one of the issues I'd like cleared up when I go back east: what are the global trends, what are the inventories and what's it going to take to get them back into balance.

Petroleum News: So again is this something you bring back to the Capitol, especially if we are in a price sensitive environment?

Stedman: As far as getting that information into the system, I'm sure I'll have some talks with my colleagues. Mia Costello will be there, too, so it's not held in confidence by any means. It's get information and bring it back. One of the best pieces of information we came back with years ago was the dynamic changes in the shale industry and how fracking was going to potentially revolutionize the production balance around the planet.

We came back from Energy Council and brought it back to the state level. At that time — this was several years ago — and we were virtually dismissed by DNR and Revenue. It turned out the information was timely and on point. That's just one example.

The Energy Council tries to stay out six to nine months ahead of current industry trends and what's coming at us. The further you try to reach out in the future, the cloudier your Ouija board is. They bring in some of the top quality presenters from around the world. What we don't do is have discussions on fiscal structures on sovereigns, in other words tax structures of oil basins, whether it's North Dakota, Norway or Alberta. North Dakota and Alberta are members; Norway is not.

That is not the subject matter or the interest of Energy Council

Now if we get into offshore and revenue sharing, that is. The position Energy Council takes is to treat all states equal. If you're going to have 37.5 (percent royalty share) for the Gulf of Mexico, you need to treat Alaska the same, the East Coast the same. Just like building here, you want all areas of the state treated the same as you go through budget issues. Maybe not equally, but fairly.

They will take positions on the in ability for Wyoming to get coal to the coast. We take positions on Keystone. We wanted Keystone permitted and constructed. We don't take a position on whether Nebraska deserves royalty for oil going through a pipeline going through their state. We work on a pretty much unanimous position. It's all states and provinces that produce energy.

Petroleum News: Now as the public goes, Energy Council is a rather elusive group, some have even said

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● EXPLORATION & PRODUCTION

ANS production down 3.3 percent month-over-month

February North Slope crude averages 512,795 bpd, down from 530,208 bpd in January; January Cook Inlet output down marginally

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 512,795 barrels per day in February, down 3.28 percent from a January average of 530,208 bpd, a drop of 17,413 bpd.

Most major reporting areas were down, with only Endicott and Alpine showing month-over-month increases.

The largest per-barrel drop was at the North Slope's largest field, BP Exploration (Alaska)-operated Prudhoe Bay, which averaged 293,913 bpd in February, down 4.58 percent, 14,109 bpd, from a January average of 308,022 bpd.

February information comes from the Alaska Department of Revenue's Tax Division which reports North Slope oil production consolidated by major production centers and provides daily production and monthly averages. More detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

Prudhoe volumes include satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris, as well as the Hilcorp-operated Milne Point and Northstar fields.

AOGCC data shows production from Milne Point averaged 19,336 bpd in January, down 6.28 percent, 348 bpd, from a December average of 19,684 bpd, and Northstar averaged 10,581 bpd in January, down 9 percent, 1,047 bpd, from a December average of 11,629 bpd. For January, Milne Point and Northstar volumes accounted for 9.7 percent of the total shown for Prudhoe.

Other production declines

The BP-operated Lisburne field, part of greater Prudhoe Bay, averaged 25,434 bpd in February, down 4.56 percent from a January average of 26,650 bpd, a drop of 1,216 bpd. Lisburne production includes Niakuk and Point McIntyre.

The ConocoPhillips Alaska-operated Kuparuk River field, the Slope's second largest, averaged 135,875 bpd in February, down 1.91 percent, 2,652 bpd, from a January average of 138,527. Kuparuk includes satellite production from Meltwater, Tabasco, Tarn and West Sak, as well as from the Eni-operated Nikaitchuq field and the Caelus Alaska-operated Oooguruk field.

AOGCC data for January shows Nikaitchuq averaged 24,529 bpd, down 3 percent, 764 bpd, from a December average of 25,393 bpd. Oooguruk averaged 9,798 bpd in January, down 13.5 percent, 1,529 bpd, from a December average of 11,327. Combined, those two fields accounted for 24.3 percent of the Kuparuk production total shown by the Department of Revenue in January.

Endicott, Alpine up

The Hilcorp Alaska-operated Endicott field and the ConocoPhillips-operated Alpine field both had month-over-month production increases.

Endicott averaged 9,511 bpd in February, up 2.1 percent from a January average of 9,318 bpd, an increase of 193 bpd. Endicott includes production from Eider and Sag Delta, as well as from the Badami field, operated by Miller Energy subsidiary Savant Alaska.

AOGCC data show Badami averaged 989 bpd in January, up 0.1 percent from a December average of 988 bpd.

The ConocoPhillips-operated Alpine field averaged 48,062 bpd in February, up 0.8 percent from a January average of 47,691 bpd, an increase of 371 bpd.

Alpine includes satellite production from Fiord, Nanuq and Qannik, with the majority of production, 68 percent in January, from the main Alpine field, followed by Fiord, 25 percent, and Nanuq and Qannik, 3.5 percent and 3.6 percent.

Cook Inlet down marginally

AOGCC data show Cook Inlet production averaged 18,050 bpd in January, down 60 bpd, 0.33 percent, from a December average of 18,110 bpd.

The largest month-over-month increase was at the Hilcorp Alaska-operated Swanson River field, which averaged 2,531 bpd in January, up 10.4 percent, 238 bpd, from a December average of 71,073 bpd.

Cook Inlet's largest field, the Hilcorp-operated McArthur River field, averaged 5,621 bpd in January, up 1.1 percent, 59 bpd, from a December average of 5,562 bpd.

The only other field with a month-over-month increase was Beaver Creek, Cook Inlet's smallest field, which averaged 120 bpd in January, up 8.25, nine bpd, from a December average of 111 bpd.

The steepest month-over-month decline was at the Hilcorp-operated Trading Bay field, which averaged 2,643 bpd in January, down 5.75 percent, 161 bpd, from a December average of 2,804 bpd.

The West McArthur River field, operated by Miller Energy subsidiary Cook Inlet Energy, averaged 1,578 bpd in January, down 4.95 percent, 82 bpd, from a December average of 1,660 bpd.

The Cook Inlet Energy-operated Redoubt Shoal field averaged 914 bpd in January, down 4.93 percent, 47 bpd, from a December average of 961 bpd.

The Hilcorp-operated Granite Point field averaged 2,705 bpd in January, down 2.37 percent, 66 bpd, from a December average of 2,771 bpd.

The Middle Ground Shoal field, operated by ExxonMobil subsidiary XTO, averaged 1,937 bpd in January, down 0.5 percent, 10 bpd, from a December average of 1,947 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● FINANCE & ECONOMY

Service sector gets hammered

Canadian drillers forced to idle rigs, eliminate jobs, cut paychecks of staff, executives, pullback from some foreign operations

By GARY PARK
For Petroleum News

The costs of the rapid erosion of Canada's upstream sector have landed squarely on supply and service companies, who are under extreme pressure to rebid on contracts or slash a minimum 20 percent off their orders.

Many of those companies have made it clear they will not play ball as they eliminate jobs and idle equipment, while some are hoping to ride out the storm by reducing the paychecks of executives, employees and directors, while pulling back from some frontier operations, or underperforming plays.

The result has been a sharp decrease in Canadian activity, with the traditional spring wind-up of the peak drilling season starting earlier and expected to drag on longer.

Calfrac leaves Colombia

Calfrac Well Services has taken drastic action beyond its domestic borders, leaving the South American country of Colombia entirely, rationalizing its Mexican unit, parking half of its fracturing horsepower in the United States and closing a coiled tubing operation in Pennsylvania.

"The pressure is there," Calfrac Chief Executive Officer Fernando Aguilar told analysts. "We've seen people parking fleets already. We've seen customers asking for more ... so the market's very competitive."

That was a dramatic mood swing from last November, when he said horizontal well completions were expected to be strong for the balance of 2014 and into 2015, led by exploration in British Columbia to build natural gas supplies for proposed LNG projects and improving performance due to new well completion technology.

Trican cutting salaries

Trican Well Service said it is cutting salaries (by 10 percent for its full-time staff and 15 percent-18 percent for senior executives), fees and costs, while reducing its North American workforce by 600 positions to save an overall C$28 million.

The company said it has already dropped a fracturing crew in each of its Eagle Ford, Bakken and Permian regions, while closing its operating base in Longview, Texas, where one fracturing crew and two cement crews had previously operated.

Calfrac and Trican both said their customers are stepping up the "intensity" of their hydraulic fracturing jobs, boosting the number of fracks in each horizontal well, and also increasing demand for more lucrative 24-hour service.

At the end of February, 289 rigs were operating in Western Canada, representing 37 percent of the industry's total fleet, the Canadian Association of Oilwell Drilling Contractors reported. That is down from 317 rigs operating at the same time last year.

Calfrac said the number of fracking intervals it performs per well in Canada has increased 73 percent over the past year and the amount of sand injected per well has doubled.

Trinidad laying off staff

Trinidad Drilling is lying off staff and making an average pay cut of 7 percent for its remaining employees, while halving its 2015 budget to C$175 million.

"We feel that a prudent approach to the coming year is important and have chosen to lower our capital expenditure level from 2014," said Chief Executive Officer Lyle Whitmarsh.

"We have postponed some rig upgrades until demand increases and have worked with our customers to meet our commitments while also conserving cash generated from our operations." A Trinidad spokeswoman said she did not know how many of the company's 3,000 employees will be laid off because an announced 20 percent reduction does not affect those who work on rigs.

The company — which operates in Canada, the United States, Mexico and Saudi Arabia — said it will "postpone upgrades previously scheduled for existing rigs and will review this decision as market conditions change throughout the year."

It said capital items purchased for new builds and upgrades that are no longer required will be placed in capital inventory for use on its existing fleet.

At the end of February, 289 rigs were operating in Western Canada, representing 37 percent of the industry's total fleet, the Canadian Association of Oilwell Drilling Contractors reported. That is down from 317 rigs operating at the same time last year. ●

Contact Gary Park through publisher@petroleumnews.com

Bottom line carries high cost

The day of reckoning is at hand for Alberta's floundering petroleum industry, with an analysis of the province's largest oil sands operations by Wood Mackenzie estimating as much as US$23 billion of cash flow will be wiped out over the next two years.

Based on information gathered from 32 companies, the consulting firm also forecasts that capital spending in northern Alberta's vast bitumen region will tumble to US$17.9 billion this year.

It doubts there will be any turnaround in those forecasts even if crude oil prices rise to US$55 a barrel this year and US$65 in 2016, as some observers are predicting.

But Wood Mackenzie said the sector is still likely to add 458,000 barrels per day of new oil sands production that is due on stream in 2015 and 2016.

The firm said the anticipated slowdown in capital investment likely means peak bitumen production will not reach 4 million barrels per day until 2024 — four years behind the earlier target.

It said the operational costs for extracting bitumen are now about US$37 per barrel for thermal-recovery projects and US$40 for mining projects, adding that the average breakeven point for production for in-situ operations is US$41 and for a mine is US$47, although full-cycle breakevens can exceed US$100 for both project types.

Calgary-based investment bank Peters & Co. released similar predictions in January for production growth of 200,000-300,000 bpd over the next three to four years, raising total output to 3 million bpd by 2020, up 1 million bpd from the end of 2014.

In an updated report in January, the Canadian Association of Petroleum Producers targeted capital spending in the oil sands sector of C$25 billion this year, off C$8 billion from its earlier forecast, while expenditures on conventional oil would slump to C$21 billion from C$36 billion last year.

"Even if projects temporarily operate at a loss, shut-ins are not expected," said the firm's principal analyst Callan McMahon.

He said the projected 62 percent decline in cash flow is based on average West Texas Intermediate crude of US$55 this year and US$65 next year.

see **BOTTOM LINE** *page 6*

NATURAL GAS

FNG, RAPA, object to FNSB requested stay

Fairbanks Natural Gas, Attorney General's Regulatory Affairs and Public Advocacy section, both oppose Fairbanks North Star Borough

By KRISTEN NELSON

Petroleum News

The Fairbanks North Star Borough has drawn objections to its Feb. 4 request for a stay in two interrelated cases pending before the Regulatory Commission of Alaska.

After the Alaska Industrial Development and Export Authority said it in late January that it proposed to purchase Pentex Alaska Natural Gas Co. and its subsidiaries, including Fairbanks Natural Gas, the borough asked RCA to stay the cases involving FNG until the state reached a conclusion.

AIDEA signed a non-binding letter of intent Jan. 26 for the purchase of Pentex, which is the holding company for several subsidiaries, including FNG, which supplies natural gas to Fairbanks, and Titan Alaska, which owns an LNG plant at Point MacKenzie which supplies liquefied natural gas for FNG's Fairbanks customers.

AIDEA told legislators in early February that the purchase is subject to a full due diligence review and will then be submitted to the AIDEA board for consideration.

AIDEA told legislators in early February that the purchase is subject to a full due diligence review and will then be submitted to the AIDEA board for consideration.

Two cases

RCA is reviewing two cases involving FNG, the first a rate case which would put the utility — which supplies some 1,100 customers in Fairbanks — under economic regulation for the first time in more than a decade, and raise its rates by 6.92 percent, and the second a proposed supply agreement with Harvest Alaska LLC, a subsidiary of Hilcorp Alaska LLC.

In its request for a stay, the borough told RCA that the timeline for the sale means that, if it goes through, it would close before or during hearings in the cases, "potentially making all parties' efforts unnecessary."

The impact of the sale could include potential exemption of AIDEA from economic regulation, the basis of the rate case, and an unclear impact on Harvest's acquisition of the Cook Inlet LNG facility from Titan. Approval of the gas supply agreement, the subject of the other case, is a precondition of the sale.

RAPA opposition

The Office of the Attorney General, Regulatory Affairs and Public Advocacy section, said in a Feb. 17 filing that it opposed the stay in proceedings because FNG had not agreed to extend the deadlines in the dockets for the two proceedings, which "imperils the viability" of the Sept. 22 deadline in one of the cases.

It also said a stay would be premature because AIDEA's letter of intent is non-binding and the purchase may not proceed.

"The time to consider a stay is when the parties are informed that the AIDEA purchase is a binding agreement," RAPA said.

It also said that while RCA could stay the dockets, statutory deadlines would continue to run, leaving "little if any time" to adjudicate the dockets if the AIDEA deal does not proceed, further complicated since a delay would require RCA to find time on its schedule for hearings, currently schedule to begin in late July and end in early August.

FNG opposition

FNG also cited the pending nature of the AIDEA purchase in its objection to the borough's motion for a stay, and said RCA "should deny the motion, but revisit the schedule in this rate case if at a future time AIDEA does file an application to acquire a controlling interest."

Attorneys for FNG noted the company filed for increased rates and a redesign of its current rate structure June 30, 2014, which would have required a decision from RCA prior to Sept. 23, 2015. FNG said it agreed to an extension until Dec. 14 for the final order.

FNG's attorneys told the commission the company "has a statutory right to have its rate case decided in a timely manner." All parties agreed to a schedule and if it is "delayed significantly, there will simply not be time to properly litigate the rate case and reach a decision" by the Dec. 14 date. ●

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BOTTOM LINE

McMahon said operators may now be faced with postponing final investment decisions on new projects.

"If oil prices were to stay lower longer" it is possible those decisions could be further delayed, although a strong recovery in crude prices could also see capital allocations brought forward, he said.

Michael Hebert, a Calgary-based analyst and author of the Wood Mackenzie analysis, said the margins in Alberta's high-cost industry "are going to be squeezed, but because of the long-life nature of the assets, producers are generally going to be forced to operate at a reduced margin or even at a loss in the short term."

But the new production "is coming on line regardless of what the short-term price is going," he said.

The outlook was reinforced by an Alberta government budget update for the 2014-15 fiscal year which ends March 31 which forecasts that the province's non-renewable resource revenue will be down C$503 million, with bitumen royalties expected to drop C$644 million, partly offset by more robust returns from conventional crude earlier in the year.

The government has already warned that it faces a budget deficit of C$7 billion in the 2015-16 fiscal year.

—GARY PARK

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● ENVIRONMENT & SAFETY

The known and unknown on dispersants

Chemicals cause spilled oil to dissipate quickly in the ocean but what may be the impact of dispersed oil on the wildlife?

By ALAN BAILEY
Petroleum News

The massive use of chemical dispersants to deal with oil spewing from the Macondo wellhead during the 2010 Deepwater Horizon disaster brought the use of this particular oil spill response technique to the forefront of many people's attentions. But what are the benefits of using dispersant chemicals in this way? And what are the downsides to a technique that can result in the relatively rapid dissipation of an ocean-surface oil slick?

On Feb. 9 during the Alaska Forum on the Environment some dispersant experts talked about the practicalities of dispersant use, and about the benefits and risks associated with the technique.

Dealing with a bad situation

Tom Coolbaugh from ExxonMobil Research and Engineering Co. stressed that an oil spill is a bad situation that people hope will not happen. A dispersant is one component of a set of response tools designed try to make that situation less bad, he said. And in choosing which tool to use, oil spill responders need to consider the net environmental benefit of using one technique versus another.

Dispersants work in a very similar manner to domestic detergents, converting a continuous oil slick into a cloud of minute oil droplets that dissipate through the water column.

By greatly increasing the contact surface area between the oil and the water, dispersion accelerates the rate at which naturally occurring microbes consume the oil, with the microbes using the oil as an energy source and a source of carbon. However, initially at least, the oil remains in the water, in droplet form, following dispersant application. So, a decision on dispersant use will depend on an evaluation of the ecological outcome of leaving the oil on the water surface versus dispersing it into the water column, taking into account factors such as places that need protection from the oil, Coolbaugh commented.

Dispersant research

Coolbaugh said that a joint industry program working through IPIECA, an international oil industry association, has been testing the effects of applying dispersants subsea, rather than on the water surface. In the Deepwater Horizon disaster nearly half of the dispersant used was injected subsea directly into the oil flowing from the Macondo well. The industry sponsored research has found that treating the source of a subsea oil plume in this way, rather than treating the resulting surface oil slick, can reduce the volume of dispersant required by a factor of five, thus greatly reducing the total volume of dispersant that needs to be applied to the water column, Coolbaugh said.

Another research initiative is investigating techniques for locating areas where oil is thickest in an oil slick, to enable the maximization of benefits gained from the application of response techniques such a dispersant use. People are also developing new dispersant delivery platforms. One company, for example, is developing a dispersant platform based on a Boeing 727 aircraft, to reduce the dispersant transportation time relative to the traditional use of slower aircraft such as the Hercules C-130, Coolbaugh said.

Consumption by microbes

Kelly McFarlin, a research student at the University of Alaska Fairbanks, has been researching the impact of dispersants on the rate at which microbes consume oil in seawater. Worldwide, more than 180 bacteria genera have species that can degrade petroleum by breaking down oil components into carbon dioxide and water. In fact, marine micro-organisms have long been exposed to natural oil seeps — it has been estimated that between 1990 and 1999 natural oil seeps released about 600,000 tonnes of petroleum per year into the world's oceans, McFarlin said. There are known natural oil seeps off the North Slope of Alaska and naturally occurring organisms in Arctic seawater that degrade petroleum, she said.

Although low water temperatures tend to increase oil viscosities and hence reduce the availability of oil to micro-organisms, researchers have found bacteria that have adapted to maintain their metabolic rates in extreme cold, McFarlin said.

Speeds up the process

McFarlin said that she has conducted tests using oil mixed into seawater samples collected near Barrow, on Alaska's North Slope. Using Corexit 9500, the dispersant used in the Deepwater Horizon response, and working at relatively low temperatures, the impact of the dispersant on the rate of microbial decomposition of the oil when the oil was vigorously mixed with the water was quite modest, McFarlin said. However, other published research has demonstrated that the impact of dispersant on the biodegradation on a simulated surface oil slick is very marked — the application of Corexit during the research resulted in the loss of 84 percent of the oil after 40 days, as compared with a 33 percent oil loss if no dispersant is used, she said.

And measurement of the carbon dioxide emitted by the microbial action on the oil indicates that most oil consumption takes place in the first 10 days of dispersant application.

The laboratory research does confirm that micro-organisms indigenous to the Arctic can biodegrade North Slope crude oil. However, biodegradation does not completely remove all oil components, with some compounds within the cocktail of oil chemicals being hard to degrade. And research is needed into the effectiveness of biodegradation in and under sea ice, McFarlin said.

Toxicity concerns

John Incarnoda from the National Marine Fisheries Service commented on what is known about the toxicity impacts on marine ecosystems of applying dispersants to spilled oil. The active ingredients in commercial dispersants are also widely used in domestic soap products and have quite low toxicity, Incarnoda said. However, the toxicity impact of applying dispersants to an oil slick is something of a two edged sword: On the one hand the dispersant increases the rate of microbe degradation of the oil and removes the oil from the sea surface, where some marine animals are active, while on the other hand the dispersion of huge numbers of oil droplets into the water column may increase the rate of uptake of the oil by marine organisms, damaging those organisms and potentially impacting the marine food chain.

Particularly at risk are fish eggs and invertebrate organisms that tend to absorb oil that they come into contact with, Incarnoda said.

Ingested oil

Sarah Allen from the NOAA Office of Response and Restoration in Anchorage said that a 2012 study into the impact of dispersed oil on one species of crustacean had shown ingested oil in the organism's gut and in fecal pellets. The excretion of the oil by the organism could move the oil to greater depths in the ocean, Allen said. More research is needed into the impact of chemical dispersion on the uptake of oil in organisms' digestive tracts, she said.

Incarnoda said that one area of concern is the potential impact of dispersed oil on fish embryos, organisms that are typically translucent and hence susceptible to enhanced toxicity because of the effects of sunlight. Researchers have consistently found that changes in acidity resulting from oil exposure causes the embryos to die from heart failure, he said.

However, much research remains to be done on the potential impacts of both dispersants and dispersed oil on the marine ecosystem. For example, nobody knows why oil impacts the acidity of a fish embryo, and there is an unanswered question regarding whether the presence of dispersant changes the rate of uptake of oil droplets by organisms such as fish eggs, Incarnoda said. ●

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NATURAL GAS

Jordan Cove LNG battles on

A Michigan-based company has won the first round of a court fight to acquire up to 20 percent of the Jordan Cove LNG project in Oregon, even though the scheme has been switched to an "export" from an "import" proposal.

The Ontario Superior Court of Justice ruled Feb. 26 that Energy Fundamentals Group is entitled to exercise an equity option that was laid out in an agreement dated July 2005 with Fort Chicago Energy Partners, a predecessor of the current operator, Calgary-based Veresen.

But a spokeswoman for Veresen said her company is considering an appeal, arguing EFG has had "no involvement in Jordan Cove as an export" facility.

She said the purchase option was issued in return for financial advice when Jordan Cove announced it was planning to import and regasify foreign-sourced LNG.

The official said Veresen would not consider EFG a suitable candidate to join those who are in the running to become equity partners capable of helping finance the US$5.3 billion project.

Option on 20 percent

Although EFG was not available for comment, it describes itself on the company website as a "project sponsor and participant" in Jordan Cove, with "an option on 20 percent ownership equity in the terminal project which it may exercise at any time prior to the commercial operating date."

Robert Kwan, an analyst with RBC Dominion Securities, said last summer that EFG's cost to join the project would be about US$100 million — a number he now says is likely to rise as the project advances.

He said the option agreement requires EFG to pay Veresen an amount equal to 20 percent of all development equity contributed prior to that time plus a premium after-tax return of 30 percent (compounded annually) on development equity from the time those costs were incurred.

Kwan said that if EFG exercises the option that would not have a material financial impact on Veresen, but it could be seen as complicating the process of

see **JORDAN COVE** page 10

● NATURAL GAS

Miller completes two North Fork gas wells

Company's first two wells at recently acquired field, NFU No. 24-26, NFU No. 42-35 come in quicker, at lower cost, than expected

By **KRISTEN NELSON**
Petroleum News

Miller Energy Resources said March 3 that it has drilled, completed and brought into production two new natural gas wells at the North Fork unit. North Fork, on Alaska's Kenai Peninsula east of Anchor Point, is operated by Miller's Alaska subsidiary, Cook Inlet Energy.

The field was acquired by Miller in early 2014 from a partnership led by Denver-based Armstrong Oil and Gas for just under $60 million in cash plus $5 million in Miller preferred stock. Miller said at the time that North Fork was producing some 7 million cubic feet per day of gas with an estimated 4.8 billion cubic feet remaining on a 10 bcf commitment to Enstar, the Anchorage-based Southcentral Alaska gas distribution company.

In February, Cook Inlet Energy was in the middle of a three-well development program at the field, its most activity there since acquiring the field. After spending much of 2014 analyzing existing seismic and well data, Cook Inlet Energy told the state in December that it intended to drill three wells — NFU No. 24-26, NFU No. 42-35 and NFU No. 31-3 — all from the existing North Fork pad using its recently purchased Glacier Rig 1, now known as Rig 37.

The two completed wells are NFU No. 24-26 and NFU No. 42-35.

Cook Inlet Energy told the state in the 50th plan of development for the unit that drilling of the NFU No. 24-26 began in late December, with drilling of the 42-35 expected to begin before the end of March. The company told the state it might "defer or substitute" NFU No. 31-3 based on analysis of information collected from the field.

In its March 3 press release Miller said combined production from the two wells was more than 2 million cubic feet per day, with the first productive zone at the 24-26 producing at some 1.65 mmcf per day. The company said once production rate from the first zone stabilizes, it "plans to open and sequentially flow-test two additional zones in that well." Miller said NFU No. 42-35 was producing at some 350 thousand cubic feet per day, "and also continues to increase as drilling fluids diminish."

"The drilling and completion of our first new wells at North Fork Field has been accomplished quicker than originally anticipated," David Hall, Miller Energy's chief operating officer, said in a statement. "We were able to deliver two new wells and put them online within a few week's time from our original expected date to deliver just one well. Additionally, we have been able to come in under budget for both, averaging well below the $9 million per well in expected gross cost."

Carl Giesler, Miller's CEO, said the company is "encouraged by the results so far, particularly at NF 24-26. Even without additional production from the zones yet to be tested, NF 24-26 will provide greater than 20% IRR at current flow rates given our contracted sales prices of more than $6.50 per Mcf."

He said Miller would "continue to exercise capex discipline by incorporating the field and well data we have gathered here together with that from the incumbent North Fork wells before taking next steps in this field. We believe focusing on lower-cost and lower-risk gas drilling at North Fork is a viable and the most capital-responsible path forward for Miller Energy in this current oil price environment."

Miller also said that it had received some $21.2 million in early February in cash tax credit payments from the state of Alaska and expects an additional cash tax credit payment of $20.6 million later in March, both payments related to operational activities in calendar 2014. ●

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ENVIRONMENT & SAFETY

Hilcorp has flow line spill at Milne

Quarter-inch hole in 10-inch line found Feb. 28; flow stopped, wells shut-in; bypass line installed; cleanup of pad, tundra begun

By KRISTEN NELSON
Petroleum News

New Milne Point field operator Hilcorp Alaska had a produced fluids release Feb. 28 from a hole on the bottom of a Tract 14 production flowline.

A statement from the unified command for the release — Hilcorp Alaska, the Alaska Department of Environmental Conservation and the U.S. Environmental Protection Agency — said the source of the leak was a quarter-inch hole in a 10-inch diameter flow line.

DEC's Division of Spill Prevention and Response said in situation reports that the release was observed at 7:50 a.m., Feb. 28. The cause of the production line rupture is under investigation.

Hilcorp spokeswoman Lori Nelson told Petroleum News that the line was installed in 2009. Hilcorp acquired 50 percent of BP's interest in Milne Point and took over as operator when the sale closed in November.

Tract 14 production line

The division said the incident was in a Milne Point Tract 14 production line, approximately 25 miles northwest of Deadhorse and 40 miles northeast of Nuiqsut, with an unknown amount of produced fluids, including crude oil and produced water released to the pad and tundra.

Tract 14 wells were shut-in, production flow stopped and the 15-foot segment of pipe containing the hole was isolated by shutting valves on either side of the hole. In a situation report issued the afternoon of March 3, SPAR said pressure inside the pipe segment was zero and that remaining product in the affected segment of pipe had been removed.

A wooden plug was inserted into the hole and that portion of the pipe wrapped to prevent further release, with containment supplies placed under the release point to reduce further environmental impact.

Production re-established

SPAR said in its March 3 situation report that crews were able to install a bypass line and re-establish normal production levels from Tract 14 wells, eliminating the risk of freeze up in the pipeline and further protecting the environment from additional spills.

Mechanical equipment and hand tools were used to clear snow and ice. Weather on the North Slope created cleanup difficulties and responders sprayed water onto the area affected by the spill to form an ice cap, preventing further migration from blizzard conditions.

SPAR said the ice cap would not interfere with recovery of product from the site.

An estimated 3,906 gallons, 93 barrels, of liquids had been recovered by vacuum truck by March 3. Some 96 cubic yards of impacted snow was removed and staged in containers for final removal and disposal.

Product volume estimates include impacted snow, ice and released product, so an actual volume of fluids released from the pipeline is unknown, SPAR said.

Recovering product

Some 38,800 square feet of gravel pad and tundra were heavily to lightly misted by fluids and the focus now is on continuing to recover spilled product from the pad and tundra. Tactics may include mechanical and hand tool removal, vacuum truck, tundra washing and collecting tundra washing water for disposal.

SPAR said there are no reports of impacted wildlife, but as a precaution, wildlife fencing has been erected to keep wildlife out of the impacted area, with wildlife hazing permits and hazing personnel activated to further deter wildlife.

The affected 15-foot pipeline segment has been emptied and the damaged portion will be removed for further inspection and analysis.

A process will be determined to estimate the amount of fluids released from the pipeline and until then the amount of affected materials recovered, including snow, ice and released fluids, will continue to be reported. ●

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JORDAN COVE

finding buyers or marketers.

Customer contracts needed

Jordan Cove has export permits from regulators in Canada and the United States to export LNG, but it is still faced with securing customer contracts for 100 percent of capacity before it can make a final investment decision.

It also needs U.S. federal environmental approval by mid-2015, if it hopes to achieve an optional startup in 2019.

Initial capacity is set at 6 million metric tons per year of LNG, liquefying 1 billion cubic feet per day of natural gas, with plans to expand by 50 percent.

Veresen decided last September to invest US$1.5 billion on a 50 percent non-operated stake in the Ruby pipeline system from gas fields in the U.S. Rockies to the LNG terminal at Coos Bay on the Oregon coast.

—GARY PARK

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NORTH OF 60 MINING news

page 13 Crockett to state lawmakers; 'Alaska has really great rocks'

www.MiningNewsNorth.com *The weekly mining newspaper for Alaska and Canada's North* Week of March 8, 2015

NEWS NUGGETS

Compiled by Shane Lasley

Willow Creek Mine on fast track

Miranda Gold Corp. March 3 said Gold Torrent plans to fast-track the Coleman gold deposit at the Willow Creek property into production in 24-30 months. Initial production estimates are for 21,000 ounces of gold annually from the mining and milling of 150 tons per day at the Southcentral Alaska project. Gold Torrent, which anticipates that gravity methods can achieve greater than 80 percent gold recovery, believes that the lack of chemicals should expedite permitting. A new resource estimate for the Coleman deposit is anticipated within two months. Miranda said a feasibility study scheduled for completion by mid-year will provide shareholders of both companies with insight into the financial parameters of mining Coleman. In addition to activities associated with mine planning and permitting, Gold Torrent will investigate the possible rehabilitation of the Enserch tunnel to access the Lucky Shot vein system for production and drilling. According to an agreement with Miranda, Gold Torrent will fund US$10 million of expenditures to incrementally earn a 70 percent joint venture interest in Willow Creek.

Dowa OKs US$5 million for Palmer

Constantine Metal Resources Ltd. March 3 said that Dowa Metals & Mining Co., Ltd. has approved a 2015 budget of US$5 million for the continued exploration of the Palmer project in Southeast Alaska. Dowa, which has the option to earn 49 percent in Palmer by investing US$22 million, had spent roughly US$10 million at the project through the end of 2014. This year's drilling will focus on extending volcanogenic massive sulfide mineralization encountered at the South Wall zone in 2014, including the 89 meters of 0.8 percent copper and 5.0 percent zinc intersected in hole CMR14-65.

Booth fills executive void at Redstar

Redstar Gold Corp. Feb. 25 reported that Ken Booth has resumed the role of interim president and CEO, replacing Toby Mayo who is leaving the company. Booth began his career as a geologist and later embarked on a career in banking and investment banking. He has served as the CEO of several public companies and is currently a director of two exploration companies. Booth is a director of Redstar and served as interim CEO of the company from March to September 2014.

RARE EARTHS

Refining rare earths

Ucore pioneers new method of separating REEs into high purity salts

By SHANE LASLEY

Mining News

Ucore Rare Metals Inc. has reached another milestone in its quest to separate rare earths into the individual elements needed in high-tech devices.

In testing molecular recognition technology, a proprietary method of separating rare earths developed by Utah-based IBC Advanced Technologies, the rare earths found at Ucore's Bokan Mountain project in Southeast Alaska have been segregated as individual salts exceeding 99 percent purity.

JIM MCKENZIE

"MRT offers a means of separating REEs to high purity in a rapid and cost effective manner, and with an exceptional level of selectivity and precision," said Ucore President and CEO Jim McKenzie.

The avant-garde technology could turn the company into a front-runner in economic and environmentally sound rare earth separation worldwide.

"It's very gratifying to see the fruition of this work and achieve such a high level of success. It is exciting to think of the business opportunities this can create for Ucore and for Alaska," said Ucore COO Ken Collison.

Sen. Orrin Hatch, R-Utah, says opportunities offered by MRT could touch numerous industrial sectors across the United States.

"This breakthrough represents advanced American technology being used to address a uniquely American challenge. Securing the most critical specialty metals is essential to fuel our nation's technology engines," said Hatch. "Rare earths such as dysprosium, terbium, and neodymium are increasingly important to U.S. military, transportation, medical, and super-computing applications as we compete across the globe."

"In my opinion, Ucore now has the opportunity to both extract and purify heavy REEs completely within the U.S. This is a remarkable win for American technology independence from China."
—Jack Lifton, principal co-founder, Technology Metals Research

Three-step process

The MRT process is designed to bind selectively with ions based on multiple parameters such as size, chemistry, and geometry. Conventional technologies such as ion exchange, solvent extraction and precipitation generally recognize differences between ions based only on a single parameter.

MRT can separate tightly interlocked rare earths into individual salts in three steps, an achievement that took up to dozens of phases using forerunner technologies.

The basic idea behind the MRT process is that certain resins, known as SuperLig® resins, grab ions based on a number of traits. The technology has already been proven in mining, especially for applications in platinum group metal recovery and removing bismuth impurities from copper.

In creating a REE separation process for Ucore, IBC created resins specifically to bind to the parameters of ions associated with rare earths.

Using a pregnant leach solution prepared from material taken from the Dotson Ridge deposit at Bokan, IBC developed a three-step process for creating nearly pure rare earths.

In the first step, scandium and cerium were extracted. The remaining rare earth elements were then separated into two groups roughly defined as

see RARE EARTHS page 14

● MINING POLICY

North offers great rocks, some concerns

Mining executives give Alaska, Yukon high marks for mineral potential, but worry about operating climates in the jurisdictions

By SHANE LASLEY
Mining News

Alaska and Yukon Territory share more than a 750-mile border in the eyes of the 485 mining executives that participated in Fraser Institute's Survey of Mining Companies 2014. This group of miners, explorers and consultants ranked these northern neighbors as two of the richest mineral jurisdictions on earth but found certain mining policies in each a cause for concern.

As a result, Yukon was ninth and Alaska was 10th on the survey's investment attractiveness index, a measure that weighs miners' perceptions of the mineral endowment and mining policies of 122 jurisdictions around the globe.


DEANTHA CROCKETT


KAREN MATTHIAS

Finland is considered the most attractive place on the planet for mining investment, according this year's Fraser Institute survey. Though only ranked 16th when it comes to pure mineral potential, this northern European jurisdiction was second only to Ireland in terms of perceptions of mining policy.

Yukon usurps Alaska

Each year, the Fraser Institute asks mining executives to ignore current policies that may sway investment decisions and rank the geological endowment of global jurisdictions. Referred to as the best practices mineral potential index, this portion of the survey is meant to level the playing field in terms of policy and measure each jurisdiction's pure mineral potential in the eyes of survey participants.

Alaska has been a strong contender in this category, taking the No. 1 spot in three of the last five years, including 2013.

For 2014, however, neighboring Yukon usurped Alaska's title of being considered the richest place on the planet to hunt for mineral deposits.

During a Feb. 25 presentation in Juneau, Alaska Miners Association's executive director told Alaska's House and Senate resource committees that this rich mineral endowment is the state's top asset in terms of drawing mining investment.

"It is said across different resources sectors that we work with that Alaska has really great rocks," she said.

Alaska dropped to third place on this year's mineral potential index does not mean the mining community thinks less of the state's mineral endowment. In fact, Alaska's score increased slightly; however, in a tight competition for the richest mining district in the world, miners viewed Yukon and Nevada as slightly better.

Northwest Territories, Yukon's diamond-rich neighbor to the east, is considered to have the fourth best rocks in the world, according to the survey results.

EPA's chilling impact

While everyone agrees that Alaska has great rocks, miners see room for improving mining policies in the state. Participants ranked Alaska 23rd globally on the Fraser Institute's "Policy Perception Index."

Considered a report card on the mining policies of governments, the PPI is a compilation of responses on a broad range of policy topics important to miners.

Environmental policies for Alaska are one area of particular concern. When asked about uncertainty concerning environmental regulations, the respondents ranked Alaska 97th, near the bottom of the 122 jurisdictions considered.

The U.S. Environmental Protection Agency's attempt to utilize its presumed authority under section 404(c) of the federal Clean Water Act to proactively veto or place restrictions on permits needed to develop the enormous Pebble copper-gold-molybdenum project seems to be one of the primary reasons miners are uncomfortable with the regulatory climate in Alaska.

"The EPA's efforts to stop the Pebble Mine project before the commencement of permitting has had a chilling impact on investment in Alaska," wrote one participant in the Fraser Survey.

While Pebble is the most glaring example of federal agencies putting up roadblocks to the permitting process, Council of Alaska Producers Executive Director Karen J. Matthias told state lawmakers they did not have to look any further than the Greens Creek Mine near the state capital to find another.

When Hecla Mining Co., owner of Greens Creek, needed more room to store tailings, it envisioned permitting a facility with the capacity to last the silver mine for decades. Instead of the 150-acre facility they requested, they ended up spending five years to obtain a permit that will last the mine about a decade.

"What ultimately was approved was an 18-acre expansion of an existing facility took five years for permitting," Matthias explained during the same Feb. 25 presentation with AMA's Deantha Crockett.

Mike Satre, community and government relations manager for Greens Creek, told lawmakers that the small expansion and long permitting window means that Hecla will be starting the approval process for another enlargement in the next couple of years.

While federal regulators are seen as holding back approvals, Alaska's Large Mine Permitting Team is praised for its efficiency.

"One-stop mine permitting greatly reduced regulatory duplication, confusion, and cost; it increases transparency and decreases time in the regulatory pipeline," one survey participant wrote about Alaska.

Crockett agrees.

"On the state side, I am sure there is always room for improvement but we are certainly happy with the timeliness as well as the rigor of the system and the standards that we have to meet," she told Alaska lawmakers.

Uncertainty in the Yukon

While Yukon is the most prized for its mineral endowment, the territory's policies are becoming increasingly less attractive to the mining community.

On the policy perception index Yukon ranked 26th, falling eight spots from its 2013 ranking and 18 positions from the 2012 survey.

Miners' perception of the territory's legal system was the largest factor in the policy drop this year.

In 2012, the Yukon Court of Appeal opined that the Yukon government has a duty to notify and, where appropriate, consult with and accommodate the Ross River Dena Council before allowing any mining exploration activities to take place within the Ross River area is one reason for this concern.

see **FRASER SURVEY** *page 14*

NORTHERN NEIGHBORS

Compiled by Shane Lasley

Red Chris trucks first copper

Imperial Metals Corp. March 2 reported that the first shipments of copper concentrate have been trucked from its Red Chris Mine to the Port of Stewart in northwestern British Columbia. Commissioning of the flotation circuit with low-grade ore from the Northwest B.C. mine began Feb. 15. During the second week of start-up, the mill feed grade was increased using ores from both the East and Main zones. On Feb. 22, the plant milled roughly 15,550 metric tons of ore over the first uninterrupted 12-hour operating shift. The mill processed a little more than 193,000 metric tons in February, producing about 2,400 metric tons of copper concentrate. Imperial says the commissioning team continues to focus on achieving continuous operations and a consistent final concentrate grade. Once the team is satisfied with the progress in these areas, more emphasis will be placed on metal recoveries and throughput.

Q1-4 yields large yellow diamonds

North Arrow Minerals Inc. Feb. 26 reported that initial results from processing of a bulk sample from the Qilalugaq Project show that yellow diamonds persist into large diamond sizes. The roughly 1,500-metric-ton sample was collected last summer from the Q1-4 kimberlite, situated nine kilometers from the Hamlet of Repulse Bay (Naujaat), Nunavut. Initial recovery data from about 46 percent of the sample have been compiled and include 5,366 diamonds greater than +1 DTC, or about one millimeter, weighing 189.97 carats from 609.0 dry metric tons of kimberlite. The recovered diamonds include 17 diamonds larger than about 0.6 carats and eight diamonds larger than one carat. The largest three diamonds recovered to date are 4.42 carats (greenish yellow cubic aggregate), 4.16 carats (intense yellow cubic aggregate), and 3.53 carats (pale yellow cubic aggregate). North Arrow reports that yellow diamonds, representing a range of hues and tones, comprise about 8.5 percent by stone count and 21.4 percent by carat weight of the +1 DTC diamonds recovered to date. North Arrow is currently working to earn an 80 percent interest in the Qilalugaq project from Stornoway by collecting and processing the current bulk sample. Stornoway has a one-time, back-in right.

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Petroleum news

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RARE EARTHS

heavy and light rare earths. A final step caused the mixtures to separate into individual rare earth salts. Individual rare earths are cleaned from the SuperLig® resin columns with a small amount of acid.

The technique created 99.9 percent pure dysprosium and neodymium salts and a 99.1 percent pure terbium salt. All three of these heavy rare earth elements are considered critical to military, high-tech and green sector applications.

"Among other firsts, this is the first time that high-purity dysprosium has been generated in the U.S. using American feedstock. What's more, the accomplishment was made without the use of traditional solvent extraction, a technology long known for the generation of unavoidable environmental pollutants," said Jack Lifton, principal co-founder of Technology Metals Research and consultant to Ucore.

The new process also recovered more than 99 percent of the REEs available in the pregnant leach solution.

The MRT breakthrough is another advance in the Bokan Mountain project becoming a domestic source of heavy rare earths.

"In my opinion, Ucore now has the opportunity to both extract and purify heavy REEs completely within the U.S. This is a remarkable win for American technology independence from China," said Lifton.

Exclusive rights

To further strengthen Ucore's foothold in the rare earths sector, the company has cut a deal with IBC for exclusive rights to the SuperLig® REE separation technology.

Upon delivery of a fully functional pilot plant, Ucore has agreed to pay IBC US$2.9 million for the rights to the potentially sector-changing technology.

"This is an important step for Ucore in obtaining the capabilities of an integrated provider of rare earth products from mine to metal," Ucore's McKenzie said March 3 in announcing the agreement.

"Perhaps most importantly, our licensing arrangement includes the application of SuperLig® technology to the world recycling and tailings processing sector – both for the recovery of rare earths and all other metals," he added.

Under the agreement, Ucore will hold 60 percent interest in a joint venture with IBC to market and sell the REE separation technology to others.

"My congratulations to Ucore and Utah-based IBC Advanced Technologies, Inc. for delivering a prospective 'missing link' in the domestic technology metals supply stream," commended Hatch.

Feasible mining

While critical, rare earth separation is only one part of the equation when it comes to securing a domestic supply of REEs – mining is another.

A preliminary economic assessment completed for Ucore in 2012, envisions the production of 2,250 metric tons of rare earth oxides per year during the first five years of full production; including an annual output of 95 metric tons of dysprosium oxide, 14 metric tons of terbium oxide, and 515 metric tons of yttrium oxide.

The PEA predicts a pre-tax net present value of US$577 million, at a 10 percent discount rate; an internal rate of return of 43 percent; a payback period of 2.3 years; and an 11-year mine life.

A feasibility study currently underway will benefit from the new recovery process and an updated resource estimate based on drilling completed since 2012, including 3,960 meters in 2014.

A 2013 resource update for the Dotson Ridge deposit, not included in the PEA, outlines an indicated resource of 2.9 million metric tons averaging 0.614 percent (39.7 million pounds) total rare earth oxides and an inferred resource of 2 million metric tons averaging 0.605 percent (26.6 million lbs.) TREOs. Roughly 40 percent of the TREOs are the higher valued heavy rare earths.

A 17-hole drill program completed in 2014 included 12 infill holes aimed at confirming the resource and five deeper holes.

Ucore said 10 of the confirmation holes cut significant mineralization, including 2.42 meters grading 1.03 percent TREO; 2.76 meters grading 1.65 percent TREO; 3.37 meters grading 1.9 percent TREO; and 2.88 meters grading 1.12 percent TREO.

The deep drilling tapped similar widths and grades some 100 meters below any previous intercepts. With the current resource extending only to an average depth of 220 meters, this evidence that the deposit runs deeper shows the potential for adding years to the life of a heavy rare earths mine being planned for Southeast Alaska.

The final blueprint of what that mine might look like will be outlined in the feasibility study due out later this year. ●

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FRASER SURVEY

Following the ruling, the Yukon government halted any new mineral staking in the Ross River area, a prohibition that recently was extended to January 2017.

"The court decision relating to the Kaska (Ross River Band Council) regarding mineral tenure has caused confusion and uncertainty and has dissuaded juniors from investing," explained one survey respondent.

Regulatory duplication and administration of regulations in the Yukon are other areas that weighed heavy on the minds of survey respondents.

"A continued lack of coordination of permitting between the environmental assessment board and the water board is causing an increase in permitting time for any projects of at least an additional year," one miner commented.

Minto, the only large mine currently operating in the territory, is one example of this longer permitting timeframe.

Capstone Mining Corp., which hoped to gain the permits to begin stripping Minto North last fall, has yet to get full authorization from Yukon regulators.

While the Yukon Environmental Socio-Economic Assessment Board issued the mining license in September, Capstone is still waiting for approval from the water license needed before stripping can begin.

Capstone provided additional information requested by the Yukon Water Board in February but does not foresee being able to strip Minto North early in the second quarter of 2015, as it had planned.

The company says the economics of Minto, without the Minto North deposit, are questionable at current copper prices.

Capstone said it will not be making any commitment of capital until an acceptable permit is received. ●

● LAND & LEASING

Finding middle road on OCS development

BOEM Alaska director says lease sale process will drive decisions recognizing both economic development and environmental priorities

By ALAN BAILEY
Petroleum News

The recent publication by the Bureau of Ocean Energy Management of a proposed new five-year oil and gas lease sale program for the U.S. outer continental shelf raised a perhaps predictable flurry of polarized objections, with those who support offshore development complaining about the plan's limitations while the environmental lobby argued for heightened restrictions, especially in the Arctic offshore.

BOEM has scheduled a series of scoping meetings as part of the process for developing an environmental impact statement for its proposed program. And during a break in one of these meetings, in Anchorage on March 2, James Kendall, BOEM's Alaska region director, talked to Petroleum News about the outer continental shelf leasing process and the ways in which his agency is trying to balance economic development with environmental protection, and with the need to protect subsistence hunting by Native communities.

"Our job is to bring the information together, so that the decision makers can make a balanced, informed decision," Kendall said. "Yes, we understand the perspectives of both sides. Both sides have legitimate concerns and interests."

The lease sale plan envisages sales in the Beaufort Sea in 2020, in the Chukchi Sea in 2022 and in federal waters of the Cook Inlet in 2021. Concurrent with the release of the lease sale plan, the Obama administration announced the withdrawal of some environmentally sensitive areas of the Arctic offshore from future leasing, including an area known as the Hanna Shoal in the Chukchi Sea. The withdrawals drew a storm of protests from Alaska's congressional delegation, which accused the administration of trying to shut down oil and gas development in Alaska's federal regions.

Statutory requirement

Kendall characterized the outer continental shelf lease sale program as a process mandated by the U.S. Outer Continental Shelf Lands Act, an act that requires the Department of the Interior to manage the OCS as a valuable resource, available for expeditious development while also being subject to environmental safeguards. He said that in Alaska BOEM is moving towards what he termed "targeted leasing," in which the agency will try to minimize conflicts between industry, subsistence activities and environmental protection. The idea is to collect objective information about the location of oil and gas resources, environmental priorities and subsistence needs, to figure out where oil and gas development makes sense, and where it does not, he said.

Kendall cited the withdrawal from leasing of the Hanna Shoal area and of a 25-mile corridor along the Chukchi Sea coast as examples of the targeted leasing approach. A number of people have identified the Hanna Shoal as very important biologically for whales and walrus; and whales migrate, feed and calve in the coastal corridor, he said. While it does not make sense to conduct oil and gas activities in these sensitive areas, there are many other areas of the Chukchi available for leasing, he said.

"We're trying to narrow it down early in the process, so that you don't end up having leases in areas that don't make sense," Kendall said.

And, while a general lack of past drilling on the Arctic outer continental shelf leads to a dependency on the results of geophysical surveying for estimates of potential oil and gas resources, available information indicates that there is plenty of oil and gas to be found in areas that could be leased, he said.


JAMES KENDALL

Allowing time

Asked about the proposal to schedule lease sales in the Beaufort and Chukchi seas quite late in the five-year sale program, Kendall responded that the timing would enable the collection of information for a comprehensive environmental analysis.

"We did that intentionally, so that we can continue to acquire good scientific information, work with all constituents and stakeholders, acquire traditional knowledge, so that when we get to the point of having a lease sale and we have to do an EIS for that lease sale, we have even more information," Kendall said, adding that experience from any drilling that Shell conducts could factor into future lease sale environmental analyses.

Kendall also emphasized that the current round of EIS scoping meetings represents the early stages of a lengthy process of developing a five-year plan, with a final decision on the plan not happening until the end of the process. At this stage the idea is to gather information and people's views, and bring all of that information together for consideration.

"It's a very hard process and we have to take into account what everyone is saying," Kendall said.

And, after BOEM has assembled the required information into an EIS document, the secretary of the Interior will make a decision on what form the final outer continental shelf lease sale plan will take, based on a view of what is in the best interests of the United States, Alaska and everybody concerned, he said.

Four-stage process

BOEM has a four-stage OCS leasing process that starts with a five-year lease sale plan, moves through the conducting of individual lease sales, permits exploration in leases and then oversees the development of oil or gas fields discovered during exploration. The agency conducts an environmental evaluation under the terms of the National Environmental Policy Act for each of these four stages. One criticism of this approach is that it may allow the deferral of difficult decisions over issues such as oil spill risks until the later stages of the process, thus placing oil companies at risk of not being able to operate in leases that they have invested in. A series of lawsuits challenging federal actions have, for example, delayed Shell's efforts to drill in the Chukchi and Beaufort seas.

Kendall defended his agency's approach, saying that on the one hand the agency does consider specific oil spill scenarios in its environmental impact statements, but that, on the other hand, it is impossible to second guess the specifics of a worst-case oil spill scenario without knowledge of where a company proposes to drill.

"As you move through the process you get more information and you can have a more robust analysis," he said, adding that technology evolves and information becomes richer during the many years that industry spends exploring, evaluating and developing leases.

"You can't do it all at the front end," he said.

Cautious approach

Kendall also commented that, with the best way of dealing with oil spills being not to have one, BOEM is taking a cautious approach to oil activities in the Arctic offshore. Shell, in its exploration drilling efforts, cannot drill into an oil bearing zone without having available well capping and oil containment systems to prevent an oil spill. And new Arctic drilling regulations being proposed by BOEM and the Bureau of Safety and Environmental Enforcement codify requirements such as an ability to drill a relief well in the event of a well blowout and the need for adequate ice-management capabilities.

"You want to prevent a spill. You want to take a cautious approach. You want all your equipment in place," Kendall said. ●

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FACILITIES

Groups sue Seattle over Shell fleet

Several environmental groups sued the Port of Seattle March 2 to prevent Royal Dutch Shell PLC from using Seattle's waterfront as a homeport for its Arctic oil drilling fleet.

The Port of Seattle in early February signed a two-year lease with Foss Maritime Co., whose client is Shell, to rent 50 acres across from downtown Seattle.

The lawsuit filed in King County Superior Court also names port commissioners and Foss. The lawsuit says the port violated state environmental laws when it did not do a review before signing the lease. The lawsuit asks the court to vacate the lease.

Patti Goldman, managing attorney with Earthjustice, said having the Shell drilling fleet at the terminal represents a different use from the previous cargo terminal with distinct environmental impacts. It should have undergone an environmental review with a public process, she said.

"The port has violated the public trust by failing to abide by our laws," said Goldman, who is representing the Puget Soundkeeper Alliance, The Sierra Club, the Seattle Audubon Society and the Washington Environmental Council.

Port: No change in activities

In a statement March 2, the port said it had not received the lawsuit, but it "believes it has complied with all necessary environmental requirements" regarding the lease with Foss at Terminal 5.

Port of Seattle CEO Theodore Fick previously wrote to Goldman, saying the port exercised its discretion and determined the lease was exempt from a review under the state environmental law. The lease did not represent a change from the activities of the previous tenant, he said.

About eight vessels would spend the winter at the terminal and major repairs would be done at a permitted shipyard, Fick said.

Foss spokesman Paul Queary said March 2 that the terminal is permitted for

see SEATTLE SUIT page 18

Mount Spurr volcano in Southcentral Alaska

● ALTERNATIVE ENERGY

Ormat terminates Mount Spurr venture

Writes off exploration costs after failing to find viable geothermal source on the flanks of the Southcentral Alaska volcano

By ALAN BAILEY

Petroleum News

Ormat Technologies has given up its attempt to find a viable geothermal energy resource on the flanks of the Mount Spurr volcano in Southcentral Alaska. During a fourth quarter earnings call on Feb. 25 Doron Blachar, the company's chief financial officer, said that the company had written off $7.3 million in Mount Spurr exploration costs.

"After conducting exploratory drilling … management concluded that the geothermal resource as well as the commercial environment would not support commercial operations in the foreseeable future," Blachar said.

Isaac Angel, Ormat's chief executive officer, said that the write off took place during the fourth quarter of 2014. Ormat has not returned calls from Petroleum News, requesting further comment on the company's Mount Spurr venture.

2008 lease sale

In September 2008, Ormat's $3.5 million purchase of 15 leases on the flanks of Mount Spurr during a state geothermal lease sale raised hopes of a new renewable energy source for generating power for the Alaska Railbelt transmission grid — the leased area lay about 80 miles west of the city of Anchorage and just 40 miles from Beluga, the closest point on the grid.

With heat clearly having to exist somewhere under the ground near the volcano, Mount Spurr presented an enticing target for geothermal exploration. Ormat began its evaluation of its acreage in 2009 by conducting various forms of aerial survey, coupled with gravity and electromagnetic measurements, seeking evidence of hot water in the subsurface and geologic structures that might be targeted as geothermal prospects.

Geothermal drilling

In 2010 the company found promising indications of a geothermal source when it drilled two core holes to depths of 1,000 feet towards the eastern side of its leased acreage. Subsequently, in 2011, the company brought in a drilling rig to drill to a depth of 4,000 feet. But that deeper well proved disappointing, with no hot water and surface temperatures no higher than 140 F.

Ormat's Mount Spurr project leader Rahm Orenstein told the Alaska Senate Resources Committee in October 2011 that the well had unexpectedly encountered a type of rock called a conglomerate, formed from detritus of various sizes, including sand, stones and pebbles. This is a type of rock that does not hold heat particularly well and there may have been mixing of warm geothermal fluid with cold glacial water from the surface, Orenstein said.

New drilling sites?

In April 2013 a consultant working for Ormat on the Mount Spurr project told the Alaska Rural Energy Conference that the company had been considering power plant options at Mount Spurr and was planning to drill again in 2014. The plan was drill farther to the west than previously, closer to the volcano's active crater, where subsurface temperatures should be higher but where the risks posed by a volcanic eruption would also be elevated. The company anticipated some field work in 2013 to identify suitable drilling sites. And in parallel with planning the drilling, Ormat was evaluating the engineering of a suitably protected power plant, the consultant said.

However, Ormat's hopes for Mount Spurr have clearly come to naught. ●

Contact Alan Bailey at abailey@petroleumnews.com

GOVERNMENT

Gas line coordinator taking new job

The outgoing federal coordinator of Alaska gas pipeline projects has a new job lined up.

Larry Persily will work as an oil and gas special assistant to Kenai Peninsula Borough Mayor Mike Navarre.

Persily is in the process of closing down the coordinator's office, which was not included in a spending bill passed by Congress late last year. The Anchorage office is scheduled to close March 6.

Navarre said Persily will follow the liquefied natural gas pipeline project, other gas line projects and legislation related to those, along with other duties as assigned. He noted that both he and Persily also are interested in state fiscal policy.

—ASSOCIATED PRESS

● ENVIRONMENT & SAFETY

BLM schedules remediation at Umiat wells

Agency has tackled NPR-A legacy wells intermittently; in recent years more federal money has become available for cleanup work

By KRISTEN NELSON
Petroleum News

The U.S. Bureau of Land Management said remediation work is scheduled to begin in March on legacy wells near Umiat within the National Petroleum Reserve-Alaska.

Alaska officials and the state's congressional delegation have been pushing for cleanup of legacy wells, 136 exploratory wells and boreholes drilled between 1944 and 1982 by the U.S. Navy and the U.S. Geological Survey.

BLM took over management of NPR-A in 1976 and inherited the responsibility to assess, plug and remediate these wells in 1982.

The agency has cleaned up some of the old wells and its 2013 Legacy Wells Strategic Plan outlined priorities and actions the agency will take to clean up NPR-A legacy wells.

Agreement with Corps

Current remediation work is being done under an interagency agreement with the U.S. Army Corps of Engineers, the agency said in a March 2 statement. The Corps has awarded a contract to Marsh Creek LLC to plug three wells, Umiat No. 1, No. 3 and No. 11. BLM said the contract also calls for removal of wellheads from Umiat No. 4, No. 8 and No. 10, with total cost of the project, including mobilization and demobilization, pegged at about $10 million.

BLM has previously done work at Umiat, with remediation work on Umiat No. 6, No. 7 and No. 9 completed in 2011 and 2012.

The agency said it has plugged 18 wells and remediated four reserve pits at a cost of nearly $86 million since 2002.

Earlier work included the 2005 emergency cleanup of the JW Dalton test well site in NPR-A — accelerated erosion along the Beaufort Sea cut about 300 feet of shoreline, putting the JW Dalton well casing within 15 feet of the sea and partially breaching the well's reserve pit. BLM secured emergency cleanup funds for the work and from February through May 2005, a team consisting of BLM employees in Alaska and elsewhere worked with a contractor to haul more than 300 truckloads of reserve pit material four miles to secure storage, pending final disposal. Ten thousand gallons of diesel fuel were removed from the well and the bore was plugged. Within six months of the cleanup, summer storms had washed the project site into the sea.

BLM said at the time that as a result of that emergency cleanup it initiated a systematic approach to inventory other old government drilled and abandoned well sites in NPR-A to determine if other sites were endangered by shoreline erosion, with 10 other sites of concern identified.

In recent years, BLM officials have said they doubted remaining sites posed a serious hazard. State regulators, notably Cathy Foerster, chair of the Alaska Oil and Gas Conservation Commissions, and state Rep. Clarisse Millett, R-Anchorage, have disagreed, arguing that there were hazards at the old sites and that it was the duty of the federal government to address those hazards.

Funding an issue

In 2013, with release of its strategic plan to plug and clean up NPR-A wells, BLM said half, or 68, of the legacy wells required no action because they had been remediated or posed no threat. The plan identified 50 wells as requiring attention, including 16 priority wells.

Funding for cleanup has been a challenge for the agency, but the Helium Stewardship Act passed in September 2013 included funds for BLM legacy well cleanup through fiscal year 2019.

The 2013 Helium Stewardship Act, which U.S. Sen. Lisa Murkowski, R-Alaska, helped author, provided $50 million for remediation and close up of abandoned oil and gas wells on current or former national petroleum reserve lands.

BLM Alaska received $10 million as a first installment of that funding and BLM expects to receive another $37 million for fiscal year 2015 and a final $3 million in fiscal year 2019. ●

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EXPLORATION & PRODUCTION

US rig count decreases 43 to 1,267

Oilfield services company Baker Hughes Inc. says the number of rigs drilling for oil and natural gas in the U.S. fell by 43 the week ending Feb. 27 to 1,267 amid depressed oil prices.

The Houston-based company said in its weekly report that 86 rigs were drilling for oil and 280 for gas. One was listed as miscellaneous. A year ago 1,769 rigs were active.

Of the major oil- and gas-producing states, North Dakota's count fell by 11, Oklahoma lost nine, Louisiana seven, Texas six, New Mexico four, Colorado three and Wyoming two. West Virginia, Ohio and Kansas dropped one each.

Alaska increased by five.

Arkansas, California, Pennsylvania and Utah were all unchanged.

The U.S. rig count peaked at 4,530 in 1981 and bottomed at 488 in 1999.

—ASSOCIATED PRESS

New geologic map; donations to GMC

The Alaska Department of Natural Resources Division of Geological and Geophysical Surveys has published a geologic map of the east-central North Slope.

The work, funded by the state and the U.S. Geological Survey's STATEMAP program, covers more than 1,200 square miles of the south-central Sagavanirktok Quadrangle of northern Alaska, the division said, a region "near existing infrastructure and prospective for oil and gas resources."

The 1:63,360-scale geologic map represents original field work conducted by DGGS in collaboration with DNR's Division of Oil and Gas.

"Data from more than 800 field stations were integrated with available well log and seismic data to produce a robust interpretation of the stratigraphy and structural geology. Important findings include the discovery of several new oil-stained locations and the documentation of fold geometries — a key component in evaluating hydrocarbon trapping mechanisms," DGGS said.

A 24-page explanatory booklet accompanies the map, along with a structural cross section, a well-log correlation, and a new regional chronostratigraphic diagram.

Map and related products can be downloaded at no charge from the DGGS website at http://dx.doi.org/10.14509/29138.

New donations to GMC

Renovations have been completed at the new Geologic Materials Center, managed by DGGS, and in early April the entire GMC collection will begin relocating to the new center in East Anchorage.

"New donations are arriving now and we anticipate many more once the facility is fully functioning in mid-2015," said Steve Masterman, the state geologist and DGGS director.

Recent oil-related donations include 300-plus feet of core from the Umiat No. 18 oil and gas well from Linc Energy.

—PETROLEUM NEWS

NATURAL GAS

FERC will prepare EIS for Alaska LNG

The Federal Energy Regulatory Commission said March 4 that its staff will prepare an environmental impact statement on impacts of construction and operation of the Alaska LNG Project.

FERC said the notice begins the scoping process the commission and its cooperating agencies will use to gather input from the public and interested agencies on the project.

Because of seasonal subsistence activities in some communities, FERC said the scoping period will remain open for an extended period, closing Dec. 4.

FERC said it would use the EIS when it determines whether the project is in the public convenience and necessity.

The commission said while the applicants — Alaska Gasline Development Corp., BP, ConocoPhillips, ExxonMobil and TransCanada — have not filed a formal application, it granted applicants' request to begin the pre-filing process Sept. 12, 2014, and has initiated a National Environmental Policy Act review under the pre-filing process. FERC said that as part of its pre-filing process it has already started meeting with the applicants, jurisdictional agencies, Alaska Native tribes, local officials and other stakeholders, discussing the project and identifying issues/impacts and concerns before an application is received. The agency also said that with this notice it is formally initiating government-to-government consultations with federally recognized Alaska Native tribes.

FERC said it is the lead federal agency in preparation of the EIS. Cooperating federal agencies include the U.S. Coast Guard, the U.S. Department of Transportation, the U.S. Army Corps of Engineers, the U.S. Bureau of Land Management and the U.S. Department of Energy.

—PETROLEUM NEWS

● FINANCE & ECONOMY

Leaner Encana ready for combat

By GARY PARK

For Petroleum News

Encana, once North America's largest natural gas producer and the bellwether Canadian energy company, is emerging from its painful makeover refocused on liquids and in fighting trim to extend its run of acquisitions last year.

Under Chief Executive Officer Doug Suttles, the company is not spooked by the oil price crash and the continuation of dismal gas prices.

It has downsized its workforce by 25 percent, slashed its capital budget by about 25 percent or US$700 million from 2014 to US$2 billion-$2.2 billion, assuming it can reduce costs by 50 percent, and reduced its key operating areas to seven from 28.

More spending to oil

For several quarters, Encana has directed more of its spending to oil production, posting volumes of 106,400 barrels per day in the final quarter of last year, up 61 percent from a year earlier, while dropping gas output to 1.7 billion from 2.7 billion cubic feet per day over the same period.

In September it set a new corporate benchmark for acquisitions, when it took over Texas-based Athlon Energy for US$5.9 billion, when oil prices were still in the upper realms, along with buying Freeport-McMoRan's Eagle Ford holdings for US$3.1 billion and selling its Bighorn acres in Alberta for US$1.8 billion.

But Suttles believes the company is in better shape to withstand a market buffeting because of an employee-led "cultural" transformation, proving to him that large organizations that are vulnerable to market fluctuations can gain strength when they have the right structures and priorities in place.

DOUG SUTTLES

"We have a highly driven culture and a proven ability to act decisively," he told analysts. "Consequently, if anyone can prosper through this part of the commodity cycle, I'm convinced it will be Encana."

Company ready to act

To back his words with deeds, Suttles said Encana is ready to act "if the right opportunity opens up in this environment and that might be for buying something or selling something. The downturns are where the big exciting stuff happens."

He said Encana's cash flow is enough to cover its costs, while considering acquisitions.

"We're at record levels of tire-kicking at the moment ... the longer this environment persists, the more likely something will occur," Suttles said.

Encana anticipates combined production from its Permian, Eagle Ford, Montney and Duvernay assets will grow to 240,000 barrels of oil equivalent per day in the final quarter of 2015 from 183,000 boepd a year earlier.

Suttles said those plays can generate cash flow and production growth even if low commodity prices extend to 2020.

Arthur Grayfer, an analyst with CIBC World Markets, said that even though final quarter 2014 results were "negative," with the company's operating profit slumping by 84.5 percent to US$35 million, the updated guidance for 2015 is "positive as capex is down about 25 percent, but production guidance is down about 2 percent." ●

Contact Gary Park through publisher@petroleumnews.com

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SEATTLE SUIT

ships to be moored while being loaded and unloaded, and "those are the services Foss will provide to the Arctic exploration fleet."

Shell considering drilling

Shell is considering offshore exploratory drilling again this summer in the Chukchi Sea off Alaska's northwest coast if it can obtain the necessary permits.

Environmental groups say the port was secretive in its lease negotiations and did not allow for proper public review. They also say Shell's drilling fleet has a poor track record when it comes to pollution and compliance with environmental laws.

In 2012, Shell's drill vessel Kulluk ran aground after it had broken free from its tow in bad weather near Kodiak, Alaska. Last year, a drilling company hired by Shell to operate a drill ship in 2012 agreed to pay $12.2 million after pleading guilty to committing environmental and maritime crimes while transiting to and from Arctic waters.

—ASSOCIATED PRESS

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REPSOL PLAN

pany returned to the region in early 2014 to drill two more wells and is planning three for this year. The well locations have been increasingly concentrated.

The company has previous given hints that it expects to sanction a project. In January 2014, Repsol Alaska Project Manager Bill Hardham said, "I feel confident it's coming. It's not a matter of if, but when." That May, Chief Financial Officer Miguel Martinez said, "We are working toward defining the most economical way to develop the area."

—ERIC LIDJI

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MUSTANG WELL

Gas in the latter half of 2014, Brooks Range Petroleum described plans to drill as many as 13 wells during 2015.

The Mustang project includes a gravel pad, a gravel access road connecting to the existing road grid at the Kuparuk River unit and a standalone production facility. The road and pad were completed last year. Construction of the facilities is running concurrently with the initial drilling operations. The Alaska Industrial Development an Export Authority is helping to finance both the early infrastructure and the facilities.

The all-season road means Brooks Range Petroleum can continue work beyond winter.

The company expects the approximately 40 million barrel oil field to initially produce between 8,000 and 10,000 barrels per day, which would leave considerable room at the 15,000-barrel-per-day processing facility to accommodate future developments nearby.

Last year, a joint venture comprising Thyssen Petroleum USA, the JK Group and Magnum Energy Partners acquired ownership of Brooks Range Petroleum from Alaska Venture Capital Group LLC and Ramshorn Investments Inc. The joint venture also acquired with a 90 percent interest in the Alaska holdings of the two former owners.

Fairway under way

The Mustang development will be the first in the region between the Kuparuk River unit and the Colville River unit, which is colloquially known as "the billion-dollar fairway."

The optimistic name reflects the advantages of operating in a region with considerable transportation and processing infrastructure, which is a rarity on the North Slope.

A standalone processing center in the region could improve the economics of other projects in the fairway. Brooks Range Petroleum operates the nearby Putu and Tofkat units and, until its recent termination, the Kachemach unit. ASRC Exploration LLC operates the Placer unit. Repsol E&P USA Inc. is exploring on leases to the north. Royale Energy Inc. intends to drill exploration wells on leases to the south as early as 2016.

Quick turnaround

After more than a decade of exploration activities, including three prolific drilling seasons, Brooks Range Petroleum farmed-in the North Tarn prospect in early 2010.

Over the 2011 and 2012 exploration seasons, the company drilled the North Tarn No. 1 exploration well, the North Tarn No. 1-A sidetrack and the Mustang No. 1 delineation well. The wells tested the Brookian formation and deeper Kuparuk formation.

The company initially expected to find some 6 million barrels of oil in the Kuparuk formation. Instead, the wells proved an estimated 44 million barrel resource, according to an independent audit by the global consulting firm DeGolyer and MacNaughton.

The larger discovery prompted the company to seek alternative ways to finance a development program, including AIDEA and the recently formed joint venture.

The region is also thought to hold considerably reserves in the Brookian formation, although the more complication geology will likely delay development for some time. ●

Contact Eric Lidji at ericlidji@mac.com

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PETRONAS LNG

Petronas delegation — incoming Chief Executive Officer Wan Zulkiflee Wan Ariffin, incumbent CEO Shamsul Azhar Abbas and Executive Vice President Wee Yiaw Hin.

Shamsul told reporters that talks to add a sixth partner could open the way for Petronas to farm-out 50 percent of the project.

With nearly 90 percent of the plant's 12 million metric tons per year of output contracted to Chinese, Indian and Japanese buyers, the venture is in good shape to make a final decision, he said.

Estimated C$36 billion

The current co-owners — Petronas 62 percent, China's Sinopec 15 percent, Indian Oil Corp. 10 percent, state-owned JAPEX 10 percent and Petroleum Brunei 3 percent — estimate the project will need C$36 billion in capital investment to start exports to Asia in 2019, including C$6.7 billion for two pipeline projects and C$11.4 billion for a liquefaction plant and tanker terminal near Prince Rupert.

Pacific NorthWest President Michael Culbert said Petronas and the British Columbia government have built a "constructive relationship over the last two years," as demonstrated by the advances made towards the first world-scale LNG facility in Canada.

Final approval still needs a number of regulatory pieces to fall into place, including a review that is expected to wrap up in June by the Canadian Environmental Assessment Agency, a federal government regulator.

Clearance has already been received by the British Columbia Environmental Assessment Office.

Although the partners called a timeout in their decision-making process 11 weeks ago, they are still proceeding with planning their engineering, procurement and construction phase. Once the submissions from three competing EPC bidders are evaluated, the future of the project can be determined.

Shamsul said the delay by Pacific NorthWest has yielded unexpected benefits because the drop in oil prices has helped lower construction costs, improving the project's economics.

"The price of equipment has dropped, the price of steel has dropped," he said. "If prices are falling we might as well wait until they stabilize before we commit ourselves."

Frustration over pipeline estimates

Coleman said the delay announced in December was also partly the result of frustration within the partnership over the cost estimates for two pipelines by TransCanada — the C$5 billion Prince Rupert Gas Transmission project and the C$1.7 billion North Montney Mainline — to carry gas from northeastern British Columbia's gas fields to Prince Rupert.

Meanwhile, the announcement in February of federal tax relief for Canadian LNG terminals could translate into billions of dollars in breaks for three major export terminals.

University of British Columbia accounting Professor Kin Lo calculated the tax measure could save companies C$75 million to C$100 million over seven years for every C$1 billion.

The cash windfall stems from an accelerated capital allowance for equipment to super cool natural gas to 30 percent a year from the original 8 percent.

The allowance enables companies to write off their investments more quickly, leaving them with better returns from the early years of a project.

In addition to the capital cost estimate for Pacific NorthWest, Shell Canada has pegged its Canada LNG scheme at C$25 billion to C$40 billion, while the Chevron-led Kitimat LNG project was earmarked at C$4.5 billion in its early days.

However, Lo said he did not think investment decisions by LNG developers were likely to be swayed too much by the tax concession, adding that the selling price for LNG is a much bigger factor.

Other cost estimates

In addition to the capital cost estimate for Pacific NorthWest, Shell Canada has pegged its Canada LNG scheme at C$25 billion to C$40 billion, while the Chevron-led Kitimat LNG project was earmarked at C$4.5 billion in its early days.

Coleman, as the chief government salesman for LNG, said he expects the industry to "take flight" this year and is counting on three plants coming on-stream by 2020.

But Jackie Forrest, vice president of research at Calgary-based ARC Financial, cautioned that the dip in oil and gas prices will be a drag on the Canadian LNG plans for a number of reasons, including the competition for financing from new developers in the United States and Mozambique.

While optimistic Canada will become an LNG player, she said startups will likely be delayed until past 2020.

In a report to clients, Bernstein and Co. senior analyst Neil Beveridge said the LNG business is suffering from an "anxiety attack" because of uncertainty over global demand.

The Bernstein report targeted startup dates of 2021 for LNG Canada, 2023 for Kitimat LNG and 2024 for Pacific NorthWest LNG.

World-class supplies

Barry Munro, Ernst and Young's Canadian oil and gas leader, said British Columbia, despite the challenges it faces from capital costs, offers world-class, potentially low-cost natural gas supplies,

"I don't know if there will be one, three or five (LNG projects in the province), but there's definitely room in the global supply-demand picture for LNG from Canada," he said.

Another promising assessment came from David Cornhill, chief executive officer of AltaGas, the lead partner in the Triton LNG project, which includes Japan's Idemitsu and a strategic partnership in the Montney gas plays with Painted Pony Petroleum.

He told analysts that the market for Montney gas remains encouraging, although "the timeline is a little cloudy at this point," with 2018-19 now viewed as "realistic."

AltaGas has signed a deal to build and operate a gas processing plant with capacity of almost 200 million cubic feet per day and agreed to buy C$50 million worth of Painted Pony shares.

Cornhill said the plant is expected to cost up to C$350 million, but the in-service date is now set for mid-2016, six months behind the original timetable. ●

Contact Gary Park through publisher@petroleumnews.com

Oil Patch Bits

Bald Mountain Air Service earns Medallion Shield

Bald Mountain Air Service, owned by lifelong Alaskans Gary and Jeanne Porter, has earned the Medallion Shield — the highest safety award by the Medallion Foundation. Each of the Five Stars represents one of the cornerstones of the Medallion Shield: controlled flight into terrain avoidance, an internal audit program, a proactive safety culture and a ground and maintenance service program. Implementing the Medallion standards for safety in all of these areas ensures a detailed control mechanism when evaluating a company's commitment to safety. Participating in the Medallion Foundation has enabled Bald Mountain Air Service to strengthen its business by providing employees and management responsibility in its safety program and continuous improvement. Bald Mountain operates full time, year around, with facilities in Deadhorse, Anchorage and Homer and specializes in complex aviation solutions for natural resource exploration, marine mammal survey, aerial photography, off-airport, Arctic all season operations, firefighting support, bulk fuel delivery and wildlife viewing.

The Medallion Shield of safety will officially be awarded to Bald Mountain Air this forthcoming fall at the Alaska Air Carriers Association aviation banquet in Anchorage. For more information about Bald Mountain visit www.baldmountainair.com.

Lolofietele joins AECOM team

NOA LOLOFIETELE

Noa Lolofietele has recently joined AECOM as a receptionist. Lolofietele has more than 5 years of combined experience in management, customer service, and in various administrative positions. Her current responsibilities as front desk receptionist include answering all incoming phone calls, greeting and directing clients and visitors to meeting rooms and offices, accepting all deliveries, preparing the daily outgoing mail, and general support of staff as necessary.

Haines new CFO for Alaska Rubber & Rigging Supply

Alaska Rubber & Rigging Supply is pleased to announce the addition of Dawni Haines as their new CFO. Haines has been an Alaska resident since 1984 after she graduated with a Bachelor of Science degree in accounting with a business minor. She has worked and played hard in Alaska since that time, enjoying the amazing people and the beautiful environment in this awesome state with her seven children and her husband of more than 32 years, Peter. Haines has worked with and for many industries in Alaska, as she has owned

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Companies involved in Alaska and northern Canada's oil and gas industry

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STEDMAN Q&A

covert for the lack of access the public has to the group. How do you reconcile that with the fact that essentially taxpayers are funding this group's membership?

Stedman: We have quite a few diplomats and very high level corporate figures or scientists, or even the Energy Information Administration, for instance. We strive to have a comfortable environment for them to do their presentation in and for them to do straight talk. If you bring in ambassadors, you have security issues to deal with. Even some of the corporate folks have security details with them. For instance, when the Venezuelan ambassador came in, there is virtually no communication between Venezuela and the U.S. government for obvious reasons. So when they came in to do a presentation on their hydrocarbons potential and the basin to Energy Council, it was of interest not only the members of the Energy Council, but the industry and the U.S. government. So it gave us an opportunity to have a rather informal environment for him to come talk to us.

Petroleum News: Closer to home with the developments on the gas line project, some people are concerned that they don't understand what direction the governor is heading. What is your take on things? Are you satisfied with what you're hearing from the administration?

Stedman: The question is the ASAP expansion versus the AKLNG process. I think we have a major gas line. I've been saying that for a couple years now and that hasn't changed. They are going through another gate here to get to FEED sometime in the fall, late fall or early winter. I don't think the Legislature should give them a hard deadline and say we are going to be here in October or not, we are going to be here to expect something.

That's not a good way to negotiate with your folks across the table, so when the administration is ready, the Legislature will take action with whatever is in front of us. From what I hear from the industry and the state agencies is that things are going well with normal negotiations and discussions. There is nothing to get alarmed about. The response and the concern some people have about parallel projects, we are only going to get one project.

Really, there is one huge target market — the Pacific basin. My personal opinion, the ASAP line without the expansion, it's not going to be economical, which means you're going to have to put billions of economic infusion to make it work, so you've got to upscale it. I agree the governor on that.

The timing issue, his job is to negotiate and put this deal together. I think he'll work that out with Exxon who is in the lead. You might as well refer to it as Exxon because they are the lead on that team and we are on that team with Exxon.

Petroleum News: Now Exxon had a small entourage here. It coincides with the governor announcing his intent to expand the scope of the ASAP line. What do you make of that?

Stedman: I think that is good. It's a positive. For Exxon to come and sit down with the governor — though I have no clue exactly what they are talking about — that's good. It's communication. Unless there is some announcement, some brouhaha happening, I'm not worried about it a bit. I like that Exxon and the governor's office are having communication. We are in this together. It's in both of our interest to get the gas line going. In fact, we are in this together broader than just the gas line.

Petroleum News: Do you have any problem with the three new appointees to the AGDC board? As you know some do because it reflects a different philosophy on how the board should be made up.

Stedman: I do not. I think they are all three good appointees. I plan on supporting all of them. They bring different skill sets to the table. Obviously (former state Sen. Rick) Halford has 20 some years of political experience. (Hugh) Short has financing experience. Then you've got (Joe) Paskvan who was born and raised in Alaska and served one term. My colleagues may not appreciate some of his opinions on things, but that's just politics. I don't think all of us agree with everybody else anytime anyway. His past positions on oil and gas stuff is of no concern to me. He, in my opinion, will look out for the state's interest and keep his scope narrowed to the board position.

Petroleum News: So what about the technical expertise that's been swapped out with the former members being removed? Is that important to have on the board or can that be obtained from someplace else.

Stedman: You can bring them in as hired hands. That doesn't concern me. If we can't get the big LNG line through the next gate, then I think this team doing the state version of the gas line will come full force and we'll see if they can put something together. If I was a betting man — which I don't go to Vegas — I would be putting my money on Exxon. They should be able to bring in that line cheaper through construction costs. Their marketing arm for selling the gas, their historical construction experience, I can make a list of strengths Exxon has over the state of Alaska and it's hard for us to outscore them on virtually anything.

Quite frankly if we were to pick a partner — in my opinion to build a $60 billion project, you need an integrated company to do this, I would pick Exxon. I think they are tough to negotiate with. Don't misinterpret what I'm saying, but if you want to build a big expensive megaproject in a small state that can't afford to have the project turn on them, you want Exxon at the table.

Petroleum News: How do you negotiate with a partner like Exxon, a company that is formidable worldwide? Do you get outside help? Do you look internally?

Stedman: I think you do. The governor has a whole team of consultants. In my opinion we in the Legislature, in particular the state, are not going to outdo them in accounting, tax, negotiations or build a project cheaper than them. I'd rather team up with them than be an opponent, I'll put it that way.

We are co-owners. Think of it that way. It's a business relationship. They will be tough in negotiations. We as resource owners have to make sure we are treated fairly. I'm sure they recognize that when the industry gets too heavy handed and too far out on the negotiations with the sovereign, they end up with unrest and they end up with stability problems in their relationship with the sovereign. It's not in their best interest to take us to the cleaners per se, because it will create problems in the future. We need a stable environment for both of our tax and royalty arena and our basic working relationship that can survive for several decades.

Petroleum News: How can the state be a regulator and a partner at the same time?

Stedman: You're talking about taking gas in kind. It's pretty tough. We are going to wait and see how that's going to work out. One of the concerns that I have is if we take it at the well head in cash, we are going to basically get nothing for it because of the cost of conditioning, shipping, liquefaction and then shipping it overseas. It's in the state's best interest to own the infrastructure, which we are doing.

I haven't changed my opinion: I'd like to buy out Trans Canada. It's an alignment issue that the state has. Not an issue with the three majors but an issue that sits in Alaska's lap itself. The other three companies are aligned. We are not. That's one of the fundamental things that is brought up over and over again during the years. We want alignment. Whether it's with oil taxes or gas, whatever, we don't want to be squabbling over the next 30 to 40 years.

TransCanada, if it were up to me, I'd buy them out. I would have never let them in the door to start with. But now that they are in there, let's buy them out. Bring them in later. If it's such a good deal, why don't the other three move over and give them a piece of their action. That decision has pretty much been made so I'm just sniffling over old negotiations.

Petroleum News: What do you want to hear from the governor about his plans for the gas line and any progress?

Stedman: Nothing until he is ready. I don't want him to make a hasty decision on any of these major things. If it takes him until the summer or fall to make a royalty issue, so be it. He's only been in there a couple of months and he's still getting his team put together. Give him time. This is a huge decision that is going to affect multiple generations of Alaskans. Hell, it will probably be 50 to 100 years.

This is a big multi-generational decision. The worst thing we can do is poke him about making a decision before he has thoroughly thought it out with the advice from his departments. So I am not concerned about the timeline. When I hear from the department that things are going well and there are negotiations — and that doesn't mean they aren't squabbling — and I hear the same thing from the industry, I don't worry about it. Let's let the process flow. Don't put artificial timelines on this.

The macro trends driving it, well the state of Alaska is not going to drive the gas line as much as world hydrocarbon economics. You can look at the Pacific basin and their need for gas. You can look at their transportation corridors out of the Middle East being bottlenecked. We've got the U.S. Navy protecting the energy supplies. You look at the age of Prudhoe and Kuparuk, and it's time start blowing the gas off. You look at Point Thomson and it's a huge gas field, and it's time to get that gas to market.

You start putting all these pieces together — the only thing I see to potentially stop this from going forward is if Exxon and the negotiating team cannot agree on a pricing structure with their markets. I don't see the state of Alaska blocking this at all. ●

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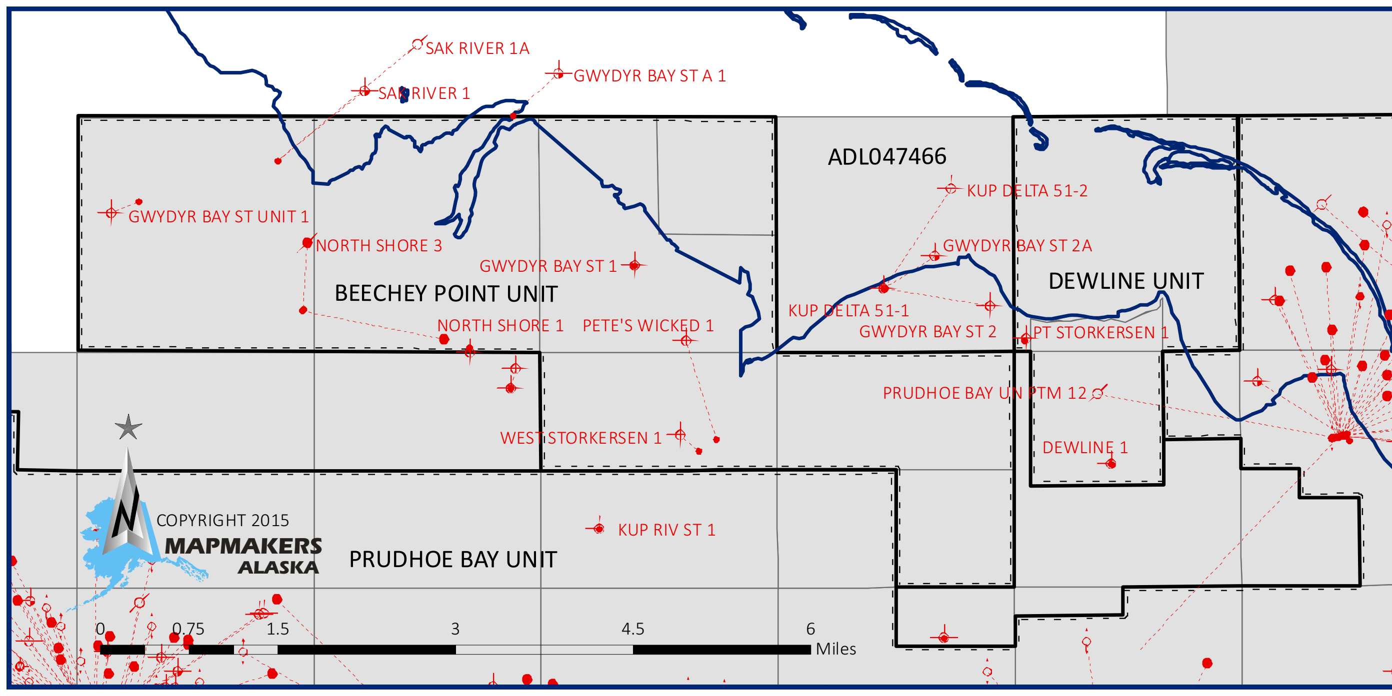
BEECHEY'S FATE



ration activities, those conditions include having a well certified as capable of producing hydrocarbons in commercial quantities.

With no such certified well at the unit, Balash believed termination was justified.

The company disagreed. In a late September 2014 letter, Vice President for Exploration Larry Vendl named two certified wells within the unit boundaries. He asked for a chance to negotiate a plan of development that would allow the company to continue exploration and development activities. The company could start as early as 2015, Vendl wrote.

Wells on leases

The leases included in the Beechey Point unit undeniably include two wells certified as capable of producing hydrocarbons in commercial quantities: Gwydyr Bay South No. 1 from 1974 and North Shore No. 1 from 2008. Both wells, though, were drilled before the state approved the Beechey Point unit in mid-2009. To the state, that made them irrelevant for extending the terms of the unit. To the company, it made no difference.

Of particular interest is North Shore No. 1, which was the first well Brooks Range Petroleum drilled in Alaska. The state certified the well in July 2008, approved the Beechey Point unit in August 2009 and asked the company to apply for a recertification by August 2010. To Brooks Range Petroleum, this "redetermination requirement" represented a changing standard. No other operator had been asked to perform a similar task, according to the company, which asked the state, in July 2010, to reconsider.

The state never responded, according to the company. The debate may be more than merely an administrative debate, though. In his September 2014 letter, Balash wrote, "It is my understanding that the well is physically incapable of producing hydrocarbons."

New plan wanted

Brooks Range Petroleum now wants to negotiate a new plan of development, citing its commitment to the project thus far. The company said it had spent more than $85.5 million exploring the region to date and had begun permitting for a proposed North Shore Development Project. The company also applied to form an initial participating area. The state had yet to rule on the application when the termination proceedings began.

What the company failed to do was drill all the exploration wells required by the unit agreement. The agreement required Brooks Range Petroleum to drill at least one well in two different exploration blocks by December 2010 and December 2012, respectively.

The company only met the first work commitment. The state subsequently extended the deadline for the second commitment until 2014, which the company also missed.

In October 2014, Balash agreed to reconsider the termination. His decision came shortly before the election of Gov. Bill Walker, which prompted a turnover of many cabinet-level positions, including the Department of Natural Resources. The new commissioner, Mike Myers, inherited the matter and had yet to issue a decision by early March.

A decade of work

Although recently sold to a multiparty joint venture, Brooks Range Petroleum Corp. started its life as the operating arm of the Alaska Venture Capital Group, which came to Alaska in 1999 to pursue sizeable oil fields passed over by the major oil companies.

The Gwydyr Bay region north of Prudhoe Bay fit the bill.

The company acquired leases through a 2001 land swap with Phillips Petroleum and arranged an exploration program. The program collapsed under the weight of various logistical problems. Still intrigued, the company acquired the acreage again in 2005.

Brooks Range Petroleum commissioned a two-well exploration program in early 2007.

North Shore targeted Ivishak

The 10,319-foot North Shore No. 1 well targeted an oil accumulation in the Ivishak formation first tested by Mobil Oil with the Gwydyr Bay South No. 1 well in 1974. The well encountered "approximately 70 feet of oil-charged Ivishak sandstone formation."

The 11,348-foot Sak River No. 1 followed up on a prospect previously included in the BP-operated Sak River unit. The well proved to be a dry hole, although the results were intriguing enough for the joint venture to consider returning to drill a sidetrack.

That winter, the company also commissioned a 130-square-mile 3-D seismic survey, which "identified two small satellite prospects to North Shore No. 1 that can be reached from the North Shore No. 1 drilling pad," according to a former partner on the project.

Combining small prospects

The results of that initial season started the company along its current path — finding a way to string together several marginally economic prospects into a single, profitable development. An early partner described the strategy as "establishing a threshold" for development. Potential solutions included two production pads or extended reach drilling.

Brooks Range Petroleum re-entered North Shore No. 1 in early 2008 to test the Ivishak and the shallower Sag River formations. The Ivishak flowed at 2,092 barrels of oil per day. A mechanical problem down hole compromised the Sag River test, although the partner estimated that an unencumbered test could have flowed at 1,000 barrels per day.

That summer, the joint venture acquired the nearby Pete's Wicked prospect from Pioneer Natural Resources Inc. BP discovered the prospect in 1997 and Pioneer acquired it in a 2003 lease sale. The acquisition provided an additional opportunity for bundling several prospects together.

A legal dispute among partners prevented drilling in early 2009. The following winter, Brooks Range Petroleum drilled the Sak River No. 1A sidetrack and the North Shore No. 3 delineation well. The company suspended both wells at the end of the drilling season.

Sak River 1A wet

"Sak River No. 1A was truly an exploration project with a pre-drill risk factor

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OIL PATCH BITS


DAWNI HAINES

and operated two accounting offices in Anchorage, since 1987, and in Eagle River, since 2006. She has volunteered in different community organizations and has held various leadership positions over the years. Most recently Haines serves as the assistant district commissioner and as roundtable commissioner for the Boy Scouts of America. She loves spending time with her family in a variety of activities including biking and hiking, and one of her favorites was hiking the Chilkoot Pass with all of its history and unmatched beauty a few years ago. Haines is enjoying working with the great people at Alaska Rubber & Rigging Supply Inc. and she looks forward to new opportunities and new business relationships in her role there.

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BEECHEY'S FATE

of 1 in 5, unfortunately the well encountered mainly water from the Kuparuk formation," Brooks Range Petroleum Chief Operating Officer Bart Armfield wrote in a completion report for the season, which was published after a mandatory two-year delay. Although the company had plugged and abandoned the original Sak River No. 1 well, it suspended the sidetrack, which would allow it to be used for providing pressure maintenance for future wells in the Sag River formation. The company said it was considering plans for a second sidetrack, which would aim for an "up-dip target of the Kuparuk," Armfield wrote.

North Shore No. 3 "identified a common oil/water contact between the Sag and Ivishak formations and presents a reduced reserve base for the North Shore development," Armfield wrote, adding that the company had now discovered reserves at North Shore No. 1, North Shore No. 3 and Pete's Wicked, which would guide future activities.

With its attentions increasingly devoted to the Mustang development, just west of the Kuparuk River unit, Brooks Range Petroleum has yet to return to the Beechey Point unit.

The original unit covered some 52,876 acres north of Prudhoe Bay. The unit contained five exploration blocks. In September 2012, the company relinquished some 42,119 acres on the western side of the unit, leaving a seven-lease unit covering some 10,757 acres.

'Close proximity'

The challenge at Beechey Point remains the same, according to Vendl.

"The potential for successful exploration and development in this area requires the compilation of several prospects with known reservoir reserves in close proximity to one another," Vendl wrote in his letter. "The smaller prospects need to be a part of a larger program; each independent prospect does not support an economic development model."

The current strategy involves combining the prospects of various operators in the region, including the East Shore prospect at Beechey Point, the ConocoPhillips-operated Kup Delta lease and the UltraStar Exploration-operated Dewline unit, all of which are located on adjacent leases (see map). At the time of the letter, in September 2014, Brooks Range Petroleum was involved in discussions with both ConocoPhillips and UltraStar, according to Vendl.

Another option, Vendl noted, would be to expand the 3-D seismic survey BP Exploration (Alaska) Inc. is commissioning for the northern end of Prudhoe Bay, including Beechey Point. "We continue to pursue the availability of the contractor to include the (Beechey Point unit) leases so that we can determine the full potential of the Kup Delta and (Beechey Point unit) eastern area, including the Dewline unit," Vendl wrote in his letter. ●

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GAS LINE BATTLE

tition with the producer-backed line, or AKLNG, of which the state is a partner

Leaving meetings with the governor feeling ill informed about his plan, Chenault introduced a bill March 2 he hopes will force Walker's hand to provide answers.

Restrictions on AGDC

House Bill 132 places restrictions on the Alaska Gasline Development Corp., which manages ASAP and the state's interest in the producer-backed line, or AKLNG

If passed, AGDC can no longer work on the upsized gas project before one of three milestones are reached:

•The state or one if its partners established last year under Senate Bill 138 withdraws from AKLNG;

•AKLNG enters its next phase, or the front end engineering and design;

•July 1, 2017.

Walker responds

The bill triggered a passionate — perhaps fiery — response from Walker not seen during his short tenure in office or perhaps from any recent governor advancing a plan, according to some who have worked in the Capitol for the last two decades.

Walker accused Chenault and co-sponsor colleagues Hawker, Rules Chair Craig Johnson, Majority Leader Charisse Millett and Majority Whip Bob Herron of tying his hands.

"I am absolutely shocked," Walker said during an uninterrupted, three-minute news conference introduction. "This flies in the face of everything the state stands for. Alaskans should be outraged. I am outraged.

"This is the epitome of why we don't have a gas line. Us not being able to have another option. What kind of negotiating position does that put us in? A horrible negotiating position.

"I'm shocked that it got this many sponsors. I really question who do these people work for. They are certainly not reading the same constitution that I'm reading. This is an outrage. The only thing that gives me pleasure today is that I'm governor and Alaska should be pretty happy about that."

MIKE CHENAULT

Walker even broke from his normal stance on prospective bill vetoes.

"You know historically I've always said I'll wait until it gets to my desk," he said. "Today I'll say I would veto this in a minute. This is the most un-Alaskan thing I've seen put together. I would absolutely veto this."

Chenault fires back

Chenault, a Nikiski Republican now serving his fourth consecutive term as House Speaker, took offense to Walker's diatribe.

"To say that he wonders who I work for, or that I don't believe in the constitution or that I'm un-Alaskan, you bet I'm insulted. Those are names that people throw around when they don't want to have an intelligent conversation with you. Hopefully we can work out our differences. Just because you and I don't agree on an idea doesn't mean I have to stoop to calling you names."

Chenault and other House and Senate leaders were to meet with Walker on Wednesday to address his burning concern: what's the plan?

"We haven't seen a plan," he said. "All we've heard is we are going to up size the line, we are going to compete against our partners who are currently moving forward on a project.

"We feel we should be negotiating with the folks who are like us and want to sell our resource for the largest amount. I think that's what the constitution says: Alaskans should be receiving the biggest benefit."

Meanwhile, House Resources had scheduled HB132 for a hearing the afternoon of March 6.

"You look and you say where are we headed? Where are we going?" Chenault said. "This bill will ferret out that information: Where are you going? What is your proposal? Who is going to pay for it?"

Even with answers, Chenault believes Walker's plan could still create pause and uncertainty among the AKLNG producing partners: ExxonMobil; ConocoPhillips and BP.

Another option

Walker says his intent to expand is simply another option and the state's past failures to advance a project warrant this approach.

"We have done everything we can in support of AKLNG," he said "We haven't slowed anything down. We fully support AKLNG. We are just not going to bet on one particular set of companies who have competing projects elsewhere, who have different options elsewhere. That's all we are saying. "

From the sidelines on the Senate side, Anchorage Democrat Bill Wielechowski called the sparing a philosophical "tug-o-war on how you should build a pipeline."

"In some ways I think what the governor is doing is brilliant," Wielechowski said. "It forces everyone to sharpen their pencils and get the best deal they possibly can. The state project is not going to go unless everybody makes money. Neither project is going to go unless everybody makes money. I just think this is a period of adjustment."

Chenault has repeatedly acknowledged the adjustment period, adding he's been willing to give Walker some space and time to learn his job. Having watched several governors enter the fray anew, all of whom had their own plans to advance a gas line, Chenault says he understands there's a daunting learning curve.

Still, he believes any governor needs to offer substance to a plan he or she puts forward.

"Normally if you have a project like what the governor has proposed, you would have the pieces in place when you roll it out so that people would at least semi understand," Chenault said. "They might not agree. They might not think that's the right way to go. But at least the plan would be out there for everyone to sit down and talk about."

—STEVE QUINN

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